Report to

Federal Treasury

Impacts of the Carbon Pollution Reduction Scheme on Australia's Electricity Markets

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TABLE OF CONTENTS

LIST OF TABLES

LIST OF FIGURES

AMENDMENTS

In this version of the final report, corrections have been made as follows:

- Exec Figure 4. The vertical axis label has been changed to TWh (from GWh)
- Figure 2.4. The labelling of the Surat basin black coal and Black coal: Central Queensland have been corrected.
- Table 3.3: Changes (absolute and percentage) in the gas and liquid fuel generation for the CPRS -15 scenario have been corrected.
- Table 4.1: Absolute and percentage changes in the wholesale price for the CPRS -15 scenario have been corrected
- Table 4.2: Absolute and percentage changes in the retail price for the CPRS -15 scenario have been corrected

ABBREVIATIONS

CoPS	Centre of Policy Studies
CPI	Consumer Price Index
CPRS	Carbon Pollution Reduction Scheme
DKIS	Darwin Katherine Interconnected System
ESC	Essential Services Commission
ETS	Emissions Trading Scheme
GEC	Gas Electricity Certificate
GGAS	Greenhouse Gas Reduction Scheme
GHG	National Greenhouse Gas
IGCC	Integrated Gasification Combined Cycle Plants
IMO	Market Operator
MMA	McLennan Magasanik Associates
MRET	Mandatory Renewable Energy Target
NEM	National Electricity Market
NGACs	NSW Greenhouse Abatement Certificates
NGGI	National Greenhouse Gas Inventory
NWSJV	North West Shelf Joint Venture
PAWA	PAWA Networks
RET	Renewable Energy Target
SHW	Solar Hot Water
SWIS	South West Interconnected System
UCC	Ultra Clean Coal
VOLL	Value of Lost Load
VREC	Victorian Renewable Energy Certificates
VRET	Victorian Renewable Energy Target

EXECUTIVE SUMMARY

The Australian Government intends to implement a carbon pollution reduction scheme. The centre piece of the scheme is an emissions trading regime, where caps on greenhouse emissions are imposed. Emitters are required to purchase permits to cover their emissions, with each permit equal to one tonne of CO_2e and the total number of permits equal to the cap.

The final design of the scheme and the caps to be imposed will be partly decided on modelling of the impacts of the emission trading scheme. The Federal Treasury has undertaken extensive modelling of the carbon pollution reduction scheme, using a suite of models of the international and Australian economies, as well as more detailed analysis of key sectors in the economy.

This report details the findings of study of the impacts on the electricity generation sector. McLennan Magasanik Associates (MMA) has been asked to model the impacts using detailed simulation models of key electricity markets in Australia. 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.

Integrated modelling approach

A key feature of this study was the use of an integrated modelling approach. Modelling of the impact of the carbon pollution reduction scheme was undertaken using a suite of models. The models covered:

- International impacts (through the use of ABARE's GTEM model).
- Domestic impacts (through the MMRF model).
- Sectoral impacts (covering the electricity, transport and land use sectors).

Outputs of the other modelling stages were a key input into the electricity market simulations. Modelling of international impacts was used to determine trends in prices of fuels used in electricity generation. International modelling was also used to determine movements in metal and commodity prices in both the reference scenario and the policy scenarios, which impact on capital costs. Movements in labour costs, which are a key determinant of operating costs, were also drawn from the whole of economy modelling The advantage of this integrated approach was that a consistent set of assumption were used across all models that enabled detailed representation of the key indirect impacts from emissions trading.

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.

Details of the modelling approach are provided in the body of the report. Six scenarios were modelled, with detail as follows:

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

Emissions to fall

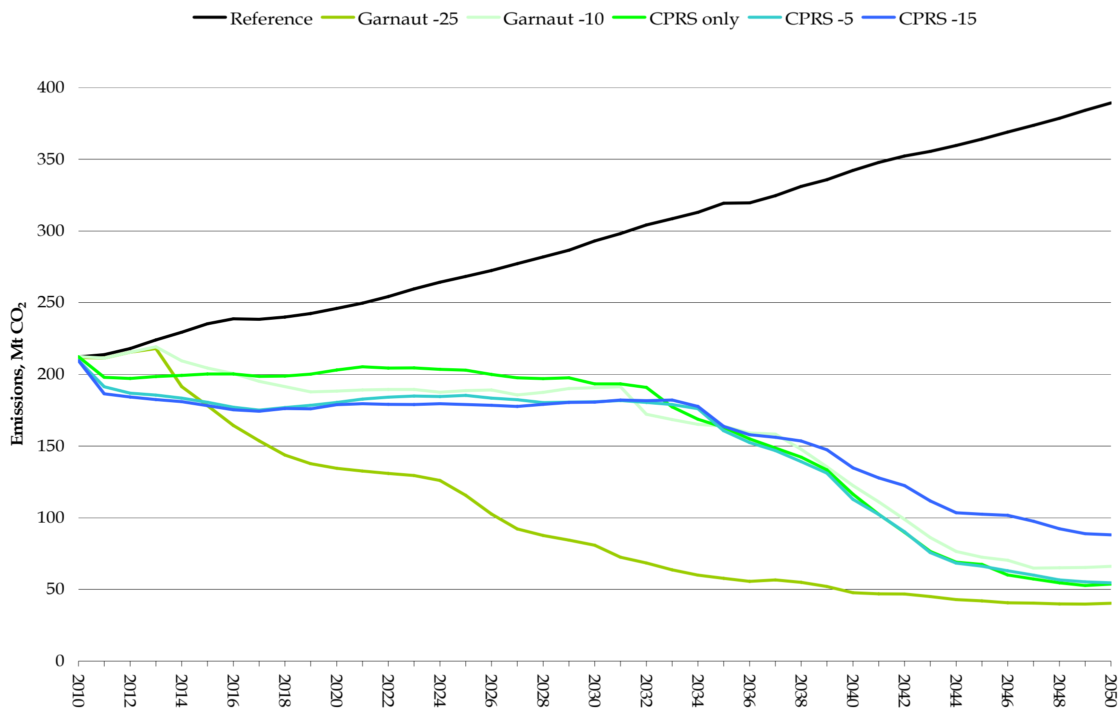
The carbon pollution reduction scheme will apply to a number of sectors in the economy. It has also been assumed that there will be linkages to other emissions trading schemes or that domestic emitters will be able to purchase offsets from eligible sources of abetment overseas to meet their domestic targets. With international linkages and given the small proportion of Australia's emissions to total world emissions, this effectively means that the potential for purchasing permits from overseas has an important bearing on permit prices in Australia.

Permit prices were determined from the modelling of the emissions trading scheme undertaken by the MMRF model. The MMRF model also determined the impacts on electricity demand.

The permit prices were input as an added variable cost in MMA's electricity market models. The variable cost to each generator that emits greenhouse gases increases by the permit price times the emission intensity of the generator. The added costs then leads to a change in the merit order of generation, with more generation from low emitting sources of generation and less from high emitting sources of generation. The added cost also changes the mix of new plant required to meet demand. Through these changes, emissions would be expected to fall.

Emissions under the various scenarios modelled are shown in Exec Figure 1. The expectation is that the higher the permit the lower the level of emissions. As can be seen in the chart, this trend is observed until the mid 2030s. The extent of reduction in emissions as permit prices increase will depend on whether the higher permit prices trigger the adoption of new low emission technologies, which in part depends on the relative marginal costs of each low emission technology. For example, the permit prices at which the first carbon capture and storage generation unit is adopted in the modelling ranges from \$45/t CO_2e to \$80/t CO_2e depending on location and time.

Exec Figure 1: Emissions from electricity generation



Beyond 2035, the relationship between permit price and emissions is more complicated. 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).

The availability of international offsets also affects the level of emissions in electricity generation. Thus, emissions from electricity generation in the Garnaut -10 scenario (with an allocation of emissions equal to a 10% cut in emissions by 2020 for the overall economy) and the CPRS Case (with an allocation of emissions equal to a 5% cut in emissions for the overall economy) are similar over the long term as the greater availability of international offsets puts a lid on the costs of permits in Garnaut -10 scenario.

Another feature of the abatement profile is that emissions from electricity generation stay flat until around 2030 under most scenarios. In fact, emissions do not go below 2000 levels (175 Mt CO_2e) for most scenarios over this period. Nonetheless considerable abatement is achieved relative to levels that would have occurred without emissions trading (see Exec Table 1. Over the long term, emissions are expected to reduce to below half of 2000 levels by 2050.

Exec Table 1: Abatement in electricity generation

	2010-2030	2031-2050	2010-2050
Cumulative emissions, Mt CO_2e pa			
Reference	5,244	6,869	12,114
Garnaut - 25	3,042	1,013	4,055
Garnaut - 10	4,122	2,360	6,482
CPRS only	4,211	2,272	6,483
CPRS - 5	3,854	2,252	6,106
CPRS -15	3,794	2,673	6,467
Average annual emissions, Mt CO_2e pa			
Reference	248	343	295
Garnaut - 25	148	51	99
Garnaut - 10	197	118	158
CPRS only	201	114	158
CPRS - 5	185	113	149
CPRS -15	182	134	158
Average annual abatement, Mt CO_2e			
Garnaut - 25	100	293	197
Garnaut - 10	51	225	137
CPRS only	47	230	137
CPRS - 5	63	231	147
CPRS -15	66	210	138
% average annual emissions to 2005 emissions			
Garnaut - 25	77%	27%	52%
Garnaut - 10	103%	62%	83%
CPRS only	105%	59%	83%
CPRS - 5	97%	59%	78%
CPRS -15	95%	70%	83%

Source: MMA analysis

This analysis indicates the contribution of electricity generation sector to the abatement task is relatively modest over the next ten years, but that the sector makes a substantial contribution to abatement over the long term.

Three factors lead to abatement in electricity generation: reduction in electricity demand in response to higher prices, switching to low emission forms of generation amongst the current stock of generating plant and entry of new low emission plant (renewable generation and efficient gas-fired generation). In the long term (from 2020 onwards), carbon capture and storage is also assumed to be available.

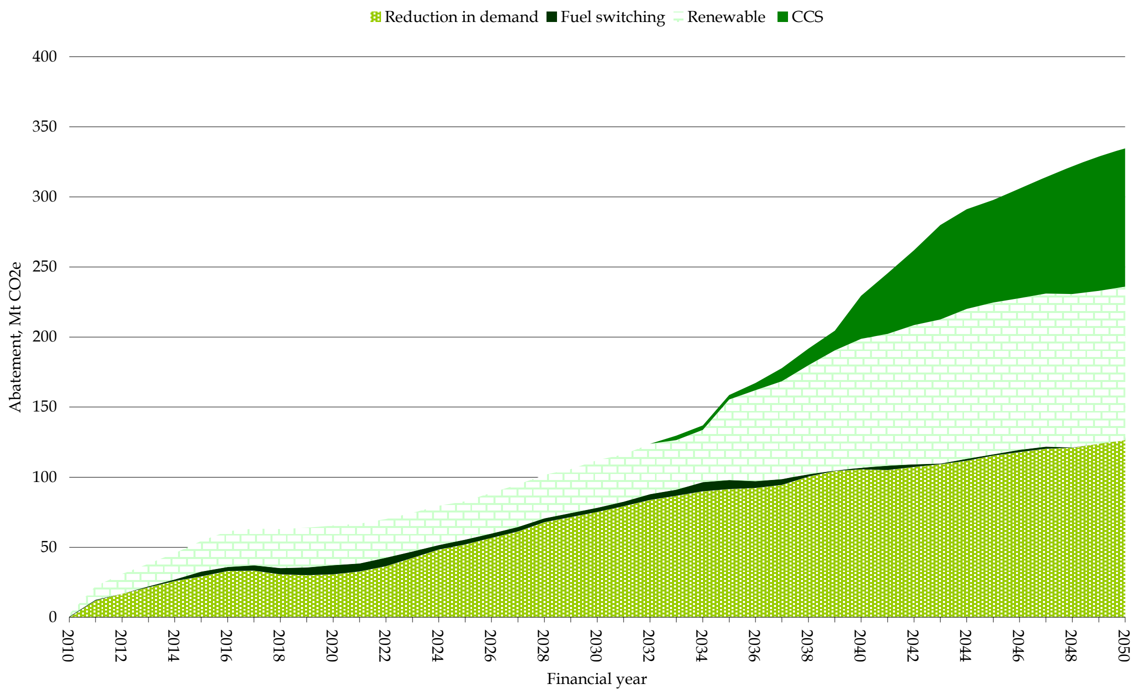
The relative importance of each option is illustrated in Exec Figure 2. In the near term, reduction in demand contributes around half of the emission reduction in all scenarios. Additional renewable energy generation also contributes to the near term abatement, with up to 40% of the abatement due to 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[1].

Importantly gas –fired generation does not make a major contribution to the abatement task in scenarios with either a RET scheme (CPRS -5 and CPRS -15 scenarios) or deep cuts early on (Garnaut -25). 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.

There are five reasons for the small role played by gas-fired generation. First, the fall in energy demand reduces the need for peaking plant, which are typically gas-fired. Second, the high cost of gas in the long term makes gas-fired generation an expensive option relative to other abatement options. Third, the inclusion of fugitive emissions on fuel reduces the abatement differential between gas-fired generation and other forms of fossil fuel generation. Fourth, 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. Finally, the cost of CCS with gas-fired generation is higher than for coal-fired generation.

[1] Note that even though CCS is assumed to be available from 2020 onwards, in most scenarios modelled this technology is not deployed until after 2030 due to its high cost.

Exec Figure 2: Sources of abatement, CPRS -5 scenario



Additional resources required

Although significant abatement is achieved, this comes at the expense of less efficient use of resources. Low emission technologies have typically higher capital costs, although the price signal provided by emission trading will help to reduce the costs over the long term.

The present value of additional resources required is estimated[2] to be:

- $10 billion for the Garnaut -10 scenario (about 9% of the present value of resource costs in the reference scenario).
- $31 billion for the Garnaut -25 scenario (about 28% of the present value of resource costs in the reference scenario).
- $8 billion for the CPRS scenario (about 7% of the present value of resource costs in the reference scenario).
- $17 billion for the CPRS -5 scenario (about 15% of the present value of resource costs in the reference scenario).
- $24 billion for the CPRS -15 scenario (about 22% of the present value of resource costs in the reference scenario).

These costs have to be compared to the benefit of deferring or avoiding the impacts of climate change from the emissions deferred.

[2] Resource costs cover fuel, operating and capital costs (for new plant only). They also include the value of less efficient use of resources due to the reduction in enery demand. Present values of resource costs are calculated for the period 2010 to 2050 using a discount rate of 8%.

Electricity prices will increase

The higher resource costs involved in electricity generation are also reflected in higher electricity prices (see Exec Table 2).

At the wholesale level, electricity prices to 2020 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.

Wholesale prices increases by more than the value of the permit price in the NEM, particularly in the period before 2020. This occurs because the nature of the market changes resulting in Victorian brown coal generators setting 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.

Another factor responsible for the relative high price increase in the period to 2020 is the fact that wholesale prices in the NEM in the reference case are depressed by the subsidies provided by the NSW Greenhouse Gas Abatement Scheme, which subsidises low emission generation by between $10/MWh to $20/MWh. Emissions trading replaces this scheme and therefore removes this subsidy and then places a cost impost (in the form of purchasing permits).

At the retail level, prices are expected to increase by 23% to 38% in the period to 2020 and by 45% to 67% in the period after 2020. The prices increase relatively less at the retail level than at the wholesale level due to the fact that wholesale prices are a small proportion of total supply costs for commercial, residential and some industrial customers. Further, increasing fees for network services, in line with recent increases in network fees, means the portion of total retail costs due to wholesale costs diminishes over time. For energy intensive industrial customers, however, the price increases are likely to be more in line with the increase in wholesale prices.

Exec Table 2: Wholesale and retail price impacts

	2010-2020	2021-2050
Wholesale (TWA) ($/MWh)		
Reference	42.4	44.7
Garnaut – 25	77.6	121.4
Garnaut – 10	63.6	102.6
CPRS only	66.0	99.0
CPRS – 5	66.3	100.1
CPRS – 15	65.3	107.8
Change in wholesale price (%)		
Garnaut – 25	83%	172%
Garnaut – 10	50%	130%
CPRS only	56%	122%
CPRS – 5	56%	124%
CPRS – 15	54%	141%
Average retail prices ($/MWh)		
Reference	102	122
Garnaut – 25	140	205
Garnaut – 10	125	185
CPRS only	128	178
CPRS – 5	130	183
CPRS – 15	131	194
Change in retail price (%)		
Garnaut – 25	38%	67%
Garnaut – 10	23%	51%
CPRS only	26%	45%
CPRS – 5	28%	50%
CPRS – 15	29%	58%

From this analysis and other analysis undertaken by MMA, the magnitude of the price increase in electricity for a given permit price depends on a number of factors. These factors include:

- Movement in gas prices. The higher the gas price, the higher the permit price required to cause fuel switching. At high gas prices, existing coal-fired generators are better able to pass on the full cost of purchasing permits through higher bids, resulting in higher electricity prices.
- Level of demand response. Large reductions in demand make it harder for new plant to come into the market. In the current set of simulations, the response to the higher

electricity prices wrought by emission trading flattens demand and makes it harder for new plant to enter into the market[3].

- The potential to game bids in the market and pass on the cost of the permits.

Electricity generation sector will be transformed

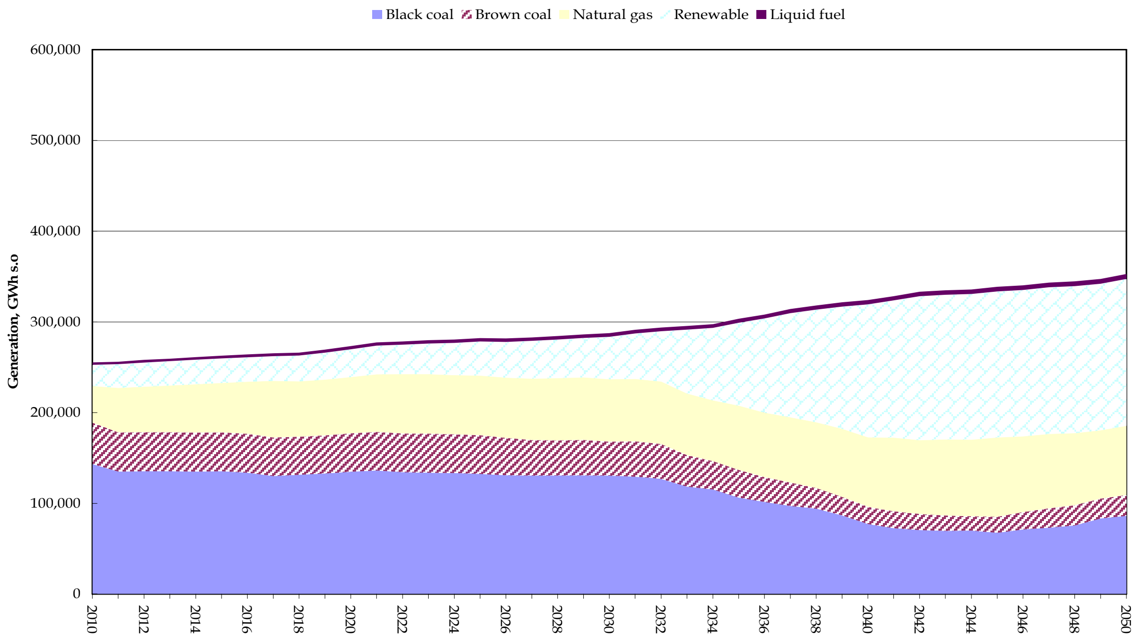
Even with modest carbon emission targets, there will be a major transformation of the electricity generation sector. Imposition of a carbon price will favour low emission generation sources such as gas-fired plant and renewable energy sources. Currently, over 75% of the generation comes from coal-fired technologies. 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. 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). This proportion would be even lower if carbon capture and storage is not successfully developed, as the coal generation in 2050 is based on the utilisation of this technology.

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.

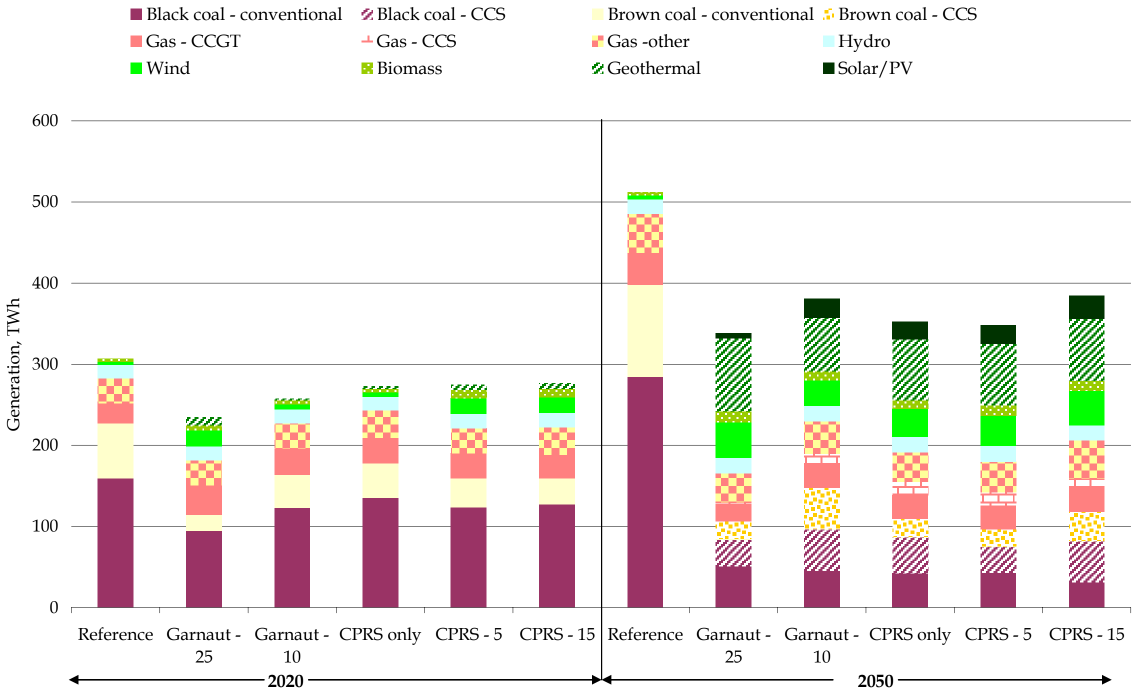
Renewable energy generation, however, is expected to increase markedly to contribute half of the generation mix by 2050. Up until 2020, the increase in renewable generation is limited in scenarios with a CPRS only, except for the Garnaut -25 scenario where the high carbon prices encourage the entry of some wind generation and geothermal generation. In cases with the expanded RET, wind generation is expected to increase markedly in the period to 2020. After 2020, the contribution of wind generation in all emission trading scenarios is muted by the restriction in the modelling that capacity is limited to 25% of the peak demand in any state. Thus, the growth in renewable generation is met by geothermal generation and then ultimately solar thermal generation to the point where these generation options dominate the renewable generation mix. The high cost of biomass generation options and the limited opportunities for hydro-electric generation limits the contribution of these technologies.

[3] New low emission plant could of course replace existing plant (rather than meeting load growth), but this requires a relatively higher permit price as the capital cost of existing plant is sunk.

Exec Figure 3: Trends in the mix of generation by technology type, CPRS only scenario



Exec Figure 4: Composition of generation by technology type



The change in mix will bring other changes as well. Renewable generation resources are more dispersed and hence the location of generation is likely to be more dispersed.

Limitations of the modelling

Although the modelling process has considered a number of key issues, the results should be interpreted with care due to the uncertainty over future developments in technologies and energy markets in general. In particular:

- The modelling assumed certain technologies that are currently being developed will be commercialised in the near future. Examples include hot dry rocks geothermal and carbon capture and storage. The modelling assumed that these technologies would work as planned, although assumptions were crafted to limit the amount of deployment of these technologies. Further, the modelling was based on the assumption that the high costs of the initial deployments of these plants (the so-called "valley of death") are overcome.
- The modelling assumed gas prices would link to international prices and thereafter follows trends in world gas prices. While this is a valid assumption, the timing of when prices are fully linked and the trajectory of prices leading to international linkage remains highly uncertain.
- Trends in capital costs of technologies are highly uncertain.
- The modelling assumed perfect foresight on the part of investors in new generation and generators. In reality, investors and generators will respond to a range of potential future trends and this could affect the timing and mix of new investment.

1 INTRODUCTION

The Federal Treasury engaged McLennan Magasanik Associates (MMA) to undertake an assessment of the cost and benefits to the electricity market of a national emissions trading scheme. It should be pointed out that the analysis has been geared towards providing insights into the economic costs and benefits to the electricity sector, where cost is defined in terms of a reduction in the productivity of resource use in the sector and benefits are defined in terms of abatement of greenhouse gases. Distributional impacts, such as changes to customer costs and losses to incumbent generators are also examined in a general way. However, the analysis of distributional impacts is only partial and further analysis and examination of these issues is required.

In this report we describe the possible impacts of the emissions trading scheme on the electricity and fuel markets. Section 2 outlines the methodology and assumptions employed to estimate the impacts on the electricity market. It also contains a description of the various scenarios modelled and explanation of various other policy measures independent of emissions trading which are relevant to the exercise.

Sections 3 and 4 present and discuss the key results of the analysis, including:

- Impact on generation mix.
- Impact on electricity prices.
- Impact on costs of generation.

In this report, monetary values are in mid 2007 dollar terms, unless otherwise stated, and stated years refer to financial year ending June.

2 METHOD AND ASSUMPTIONS

2.1 Overview: interaction between models

Examination of the abatement potential and cost of an emissions trading scheme requires the use of both bottom-up and top-down economic modelling.

- An initial electricity demand forecast was provided by Treasury.
- Using this demand, MMA modelled the impact of different options on the stationary energy sector. The output of the modelling included: the impacts on energy prices; impacts on the costs of different types of generation; fuel usage; and the interaction of scenarios and policy options with other greenhouse policies such as the extended MRET. Timing and type of new investments in generation for each region was also an output of the modelling.
- The outputs of the MMA modelling were then fed into the MMRF model to determine the impact of different scenarios and policies on the broader Australian economy.
- The iterative procedure between MMRF and MMA continued until there was convergence between demand and supply.

2.2 Input assumptions

The first stage of the modelling was to develop input assumptions about the electricity market. To do this MMA used an extensive database on:

- Electricity generation and supply, and stationary energy activities
- Costs of existing and new technologies for electricity generation

The database tracks historic and projected changes in technology costs over time and the availability of the technologies. The database also contains the cost implications of fuel substitution to reduce emissions and hence allows for the modelling of conventional gas and coal fired options of varying capacities and capabilities, new generation technologies (clean coal, fuel cells, renewable energy) and modifications to existing generators (upgrades, re-powering, conversion options).

2.3 Modelling Impacts on the Electricity Market

The second stage involved detailed modelling of the electricity markets over the timeframe of the study using MMA bottom up models of these markets. MMA's model of the National Electricity Market (NEM), South West Interconnected System (SWIS) and the Darwin Katherine Interconnected System (DKIS) simulates the market to determine:

- Dispatch of generating plant and electricity supply costs arising from this dispatch for each year

- Timing and type of new investments in electricity generation and for each region
- Impact of schemes such as Queensland's Gas Electricity Scheme and renewable energy targets on dispatch and electricity prices.

Outputs from the bottom up models are then input into the MMRF model of the Australian economy.

Modelling the impact of the abatement policies on the electricity market is a complex process. It requires iteration between a number of models to determine both the direct impacts and interactions between the various schemes. For example, emissions trading will directly impact on the type and cost of renewable generation facilitated under the Renewable Energy Target (RET) scheme.

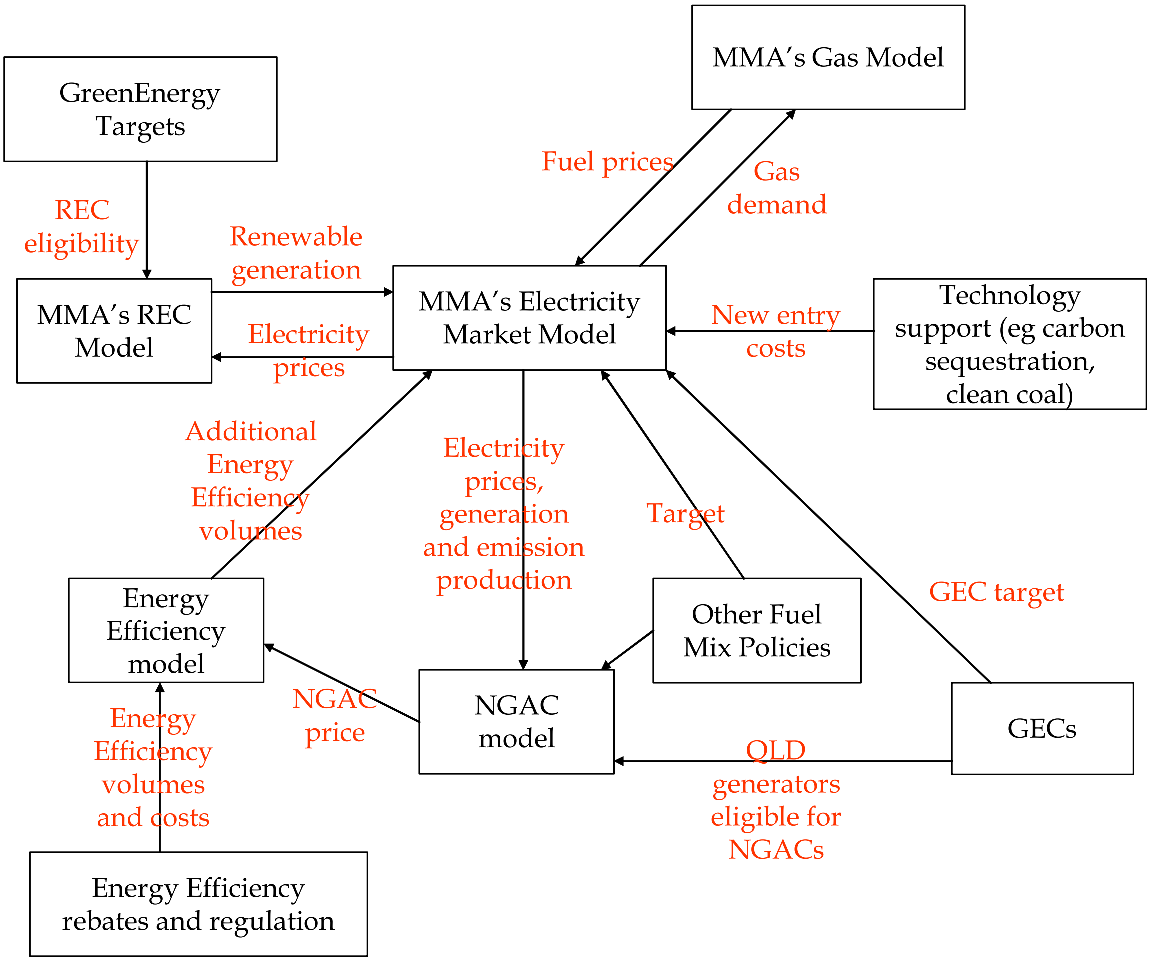
Generally, an abatement policy will directly impact on the electricity market in one of two ways. An abatement policy will:

- Vary the energy demand volume and profile
- Vary the net marginal cost of generation and hence the merit order of dispatch, through a price impost engendered through emissions targets. Emissions trading schemes impact on the marginal cost of generation and hence the merit order of power plants. To the extent that these policies impact on electricity prices these policies could also impact on demand.

Energy efficiency programs were not modelled explicitly by MMA. Demand responses were captured in the MMRF modelling.

Figure 2-1 shows the interactions between the MMA models used, and how the abatement policies were incorporated into the analysis. The key models are discussed in more detail below.

Figure 2-1: Diagram of MMA's suite of models for assessing impact on energy sector



Our approach to modelling the electricity market, associated fuel combustion and emissions was to utilise electricity demand forecasts derived from the MMRF Model in our STRATEGIST models of the major electricity systems in Australia. The model accounts for the economic relationships between generating plant in the system. In particular, the model calculated production of each power station given the generation availability of the station, the availability of other power stations and the relative costs of each generating plant in the system.

Modelling of the electricity markets was conducted using a multi-area probabilistic dispatch algorithm. The algorithm incorporates:

- Chronological hourly electricity loads representing a typical week in each month of the year. The hourly load for the typical week is consistent with the hourly pattern of demand and the load duration curve over the corresponding month
- Chronological dispatches of hydro and pumped storage resources either within regions or across selected regions (hydro-electric plant is assumed to shadow price to maximise revenue at times of peak demand)
- A range of bidding options for thermal plant to maximise profit from trading in the spot market is assumed up to the time new plant are needed. After new plant are

needed, all new base load plants follow Bertrand bidding with the remaining plants bid at short run marginal cost plus an additive factor in all regions. For existing plants, and were formulated based on a Cournot gaming algorithm which allowed generators to adjust plant availability to maximise profits

- Chronological dispatch of demand side programs, including interruptible loads
- Estimated inter-regional trading based on average hourly market prices derived from bids and the merit order and performance of thermal plant, and quadratic inter-regional loss functions
- Scheduled and forced outage characteristics of thermal plant.

By projecting expected levels of generation for each generating unit in the system, the model projected emissions. The level of utilisation depended on plant availability, their cost structure relative to other plant in the system and bidding strategies of the generators.

New plant, whether to meet load growth or to replace uneconomic plant, were chosen by the algorithm on two criteria:

- To ensure electricity supply requirements are met under most contingencies. We used a maximum energy not served of 0.002%, which is in line with the planning criteria used by NEMMCO. Minimum reserve margins were also respected for each region. Plant will always be installed in the model to meet these criteria
- Revenues earned by the new plant equal or exceed the long-run average cost of the new generator. Additional plant could be installed according to this criterion above that required satisfying the first criterion.

This analysis was based upon 12 year period blocks, with each subsequent period modelled chosen to overlap the previous two years.

Each power plant is considered separately in the model. The plants are divided into generating units, with each unit defined by minimum and maximum operating capacity, heat rates, planned and unplanned outages, fuel costs and operating and maintenance costs.

Information required to project generation, emissions and system costs, include:

- Forecasts of load growth (peak demand, electricity consumption and the load profile throughout the year)
- Operating parameters for each plant including heat rate as a function of capacity utilisation, rated capacity, internal energy requirements, planned and unforeseen outage time
- Data on fuel costs for each plant including mine mouth prices (or well head prices in the case of gas), rail freights (or transmission costs in the case of gas), royalty arrangements, take-or-pay components, escalation rates, quantity limits and energy content of the fuel

- Variable unit operating and maintenance costs for each plant (which may also vary according to plant utilisation)
- Fixed operating and maintenance costs
- Emissions production rates by fuel type
- Annual hydro energy and allocation of generation on monthly basis
- Capital costs for new generating plant.

2.4 Modelling of Emissions Trading

Details of the approaches used to model the different design options follows. As the ETS is likely to significantly affect the electricity generation sector, the modelling of policies was undertaken by MMA using the simulation model of the electricity market. The impacts on electricity supply costs, electricity prices and generation by technology type was input into the MMRF model to determine wider economic impacts.

As the permit price increases, the variable cost of each emitting generator also increases, with the level of increase in the variable cost of each generator dependent on its emissions intensity. For each generator, the variable cost increases according to the following formula:

*Variable cost increase ($/MWh) = Thermal efficiency[4] (GJ/MWh) * Emissions intensity of the fuel (t CO_2e/GJ) * Permit price ($/t CO_2e).*

As the variable cost varies, abatement occurs in two ways. First, the merit order of dispatch of generating plant will change so that more generation from low emitting generators occurs. The short run marginal cost of high emissions units will increase relatively more than the short run marginal cost of low emitting plants. At some permit price level, the low emitting plant will have a lower short run marginal cost than high emitting plant, causing these plants to be displaced ahead of high emitting plant. The permit price at which this happens depends not only on the carbon impost, but is heavily influenced by the relative fuel costs.

The fuel emissions intensities and thermal efficiencies input into the model are shown in Appendix A.

Second, as permit prices increase, the selection and timing of entry of new plant can change. The model selects new plant based on a hierarchy of long-run costs. Of the options available, the generation option which minimises long-run costs of generation is chosen when a new plant is required.

Demand response to price was modelled as part of the iteration process with the MMRF model.

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4 Thermal efficiency is the efficiency with which the energy in the fuel is converted into electricity. Thus it is equal to the ratio of the energy content of the fuel used for generation (GJ) and the amount of electricity generated (MWh).

2.5 General assumptions

A number of high level assumptions are employed in the modelling of all indicative policy scenarios. The following list summarises the high level assumptions while further detail can be found in Appendix A.

2.5.1 Market Structure and Modelling Approach

The market is assumed to operate to maximise efficiency and is made up of informed, rational participants.

The study period is 2005 to 2050, with emissions trading policies assumed to commence in either 2010 or 2013.

Capacity is installed to meet the target reserve margin for the NEM, SWIS and the DKIS.

Any changes in wholesale prices will flow through to retail prices. Price increases are therefore borne by the broad customer base.

Availability, heat rates and capacity factors of all plants in the NEM, SWIS and DKIS (including non-renewable generators) are based on historical trends and other published data.

2.6 Additional Policies

As a general principle in the Reference modelling, existing policy measures were retained. In the electricity sector, these included the Queensland Gas Electricity Generation Target (in its expanded form), and the NSW and ACT Greenhouse Gas Reduction Scheme (GGAS). The renewable energy target was limited to the existing MRET and VRET schemes, with the expanded MRET scheme (with an ultimate target of 45,000 GWh in 2020) included in some of the policy scenarios. A brief description of these schemes follows:

- The **Queensland Gas Electricity Generation Target** is designed to diversify the energy mix for the coal rich state. The scheme began on 1 January 2005 and was to continue for 15 years. It mandates electricity retailers to source at least 13% of their energy from gas-fired generation. A Gas Electricity Certificate (GEC) is created for every MWh of eligible gas-fired electricity and is required to be surrendered to the Regulator by Queensland electricity retailers and other parties. The scheme allows for some flexibility, with liable entities able to choose to create either GECs, or alternatively NGACs, depending on the respective markets. In the recent Clean Energy Bill, it was confirmed that the target will be increased to either 15% or 18% depending on the design of the ETS. Here, the target was modelled to increase to 15% by 2010 and remain at that rate thereafter until the termination of the scheme in 2020.
- The **NSW Greenhouse Gas Abatement Scheme** (GGAS) began on 1 January 2003 for NSW and 1 January 2005 for the ACT and ceases at the commencement of an emissions trading scheme. The scheme sets and regulates mandatory emissions abatement

targets on both the production and use of energy. A benchmark was established state-wide, initially at 8.65 tCO_2e per capita, with this target dropping linearly to 7.27 tCO_2e from 2007 until the close of the program. Under the scheme, eligible participants can create NSW Greenhouse Abatement Certificates (NGACs) by electricity generation activities, carbon sequestration activities, demand side abatement activities or large user abatement activities. These certificates are worth the equivalent of one tonne of carbon dioxide (CO_2). Retailers and other parties involved in the direct sale of electricity are required to surrender certificates to the Compliance Regulator (IPART) for a benchmark amount of CO_2. The penalty for non-compliance is $11.50 per tonne of CO_2. In the absence of any federal emissions scheme, this penalty is due to be raised by $1 per year from 2010 to 2013. The penalty is adjusted annually in line with the Consumer Price Index (CPI). Liable parties may surrender RECs in substitution for NGACs, and importantly, NGACs can be created anywhere in the NEM.

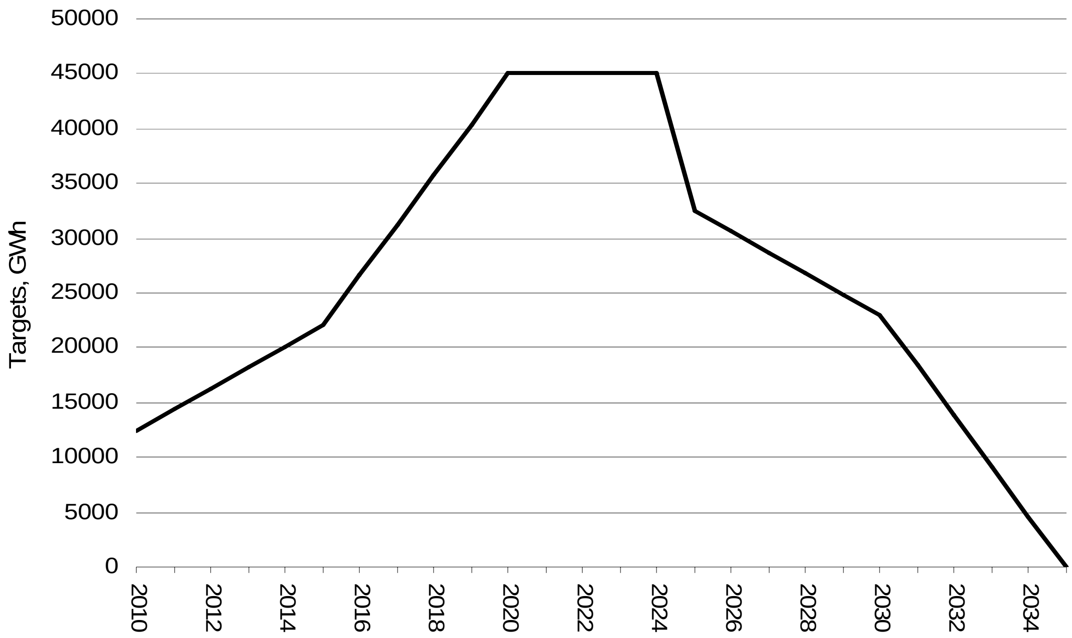
- The **Mandatory Renewable Energy Target (MRET)** commenced in 2001 and was designed to integrate a renewable energy industry within the electricity market. The target reaches 9,500 GWh per annum by 2010 and remains at this level until the scheme finishes in 2020. It is a national scheme that requires larger wholesale purchasers of electricity to surrender Renewable Energy Certificates (RECs) in proportion to their purchases. Each REC is worth 1 MWh of energy and may be banked for a period up to three years.

- The **Victorian Renewable Energy Target** (VRET) commenced on 1 January 2007 and sets a target of 10% renewable energy by 2016 and excludes old hydro systems and solar hot water. The scheme is regulated by the Essential Services Commission (ESC), and mandates retailers and large wholesale purchasers of electricity to acquire and surrender Victorian Renewable Energy Certificates (VREC), each worth 1 MWh of eligible renewable energy. Each liable entity has to yield sufficient certificates to satisfy a percentage of its electricity purchases for the year. The target increases from 0 GWh in 2007 to 3,274 GWh (estimated as 10% of Victorian demand) in 2016, and stays constant to 2022. The scheme continues up to and including 2030, with a declining target post-2022. Until 2020, the VRET scheme runs concurrently with MRET. Under the VRET legislation, electricity generated from renewable sources that have already been or are intended to be accredited to meeting the MRET, cannot be ascribed to VRET obligations. Consequently, electricity purchasers must simultaneously source sufficient renewable energy to realise both targets.

- The expanded **Renewable Energy Target** (RET) shall impose a target of 45,000 GWh of renewable energy additional to existing plants by 2020. The assumed targets are given in Figure 2-2. Solar water heaters were assumed to be eligible to create certificates under the new scheme. Pre-2007 generators were assumed to be eligible to claim under the existing MRET target of 9,500 GWh only. Unrestricted banking is also assumed.

- The **GreenPower** scheme is a national initiative that complements the renewable energy targets. Small-scale consumers may purchase a percentage of their electricity from renewable sources other than those already accredited to the renewable target scheme. The effect of GreenPower is explicitly modelled in MMA's renewable model, with future sales projected from current registry data.

Figure 2-2: Expanded RET annual target



2.6.1 Demand

The MMRF model supplies an energy demand forecast by industry classification and State for each individual scenario. Annual demand shapes are 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 is determined from Annual Reports and NEMMCO data.

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

2.6.2 Renewable Technologies

The capacity factor for existing hydro generators is assumed to be based on normal inflow conditions, with assumptions for Tasmania updated to current Hydro Tasmania predictions. Capacity factors for wind generation vary by state and location and vary from 25% to 43%.

Penetration into the market of intermittent technologies such as wind is dependent on the ability of the system to absorb such generation. The amount of installed wind capacity in each region was capped at 25% of that region's peak demand, with the exception of South Australia where this cap was allowed to be exceeded if the transmission network to Victoria was upgraded (by the model).

Both existing (hydro, wind, biomass, SHW) and predicted technologies (geothermal, high temperature solar thermal and wave) were considered, with capacity limitations as determined by previous MMA research. There are limited new hydro-electric and biomass resources, with the latter limited by host industry expansion and fuel transportation costs. Aside from the constraint of above, wind resources will eventually be limited by the unsuitability of sites. A conservative approach is adopted for the likely success of geothermal. Aside from a small demonstration project at 10 MW in 2013, geothermal is assumed not to become available on a large scale until 2017 and is constrained to 12,000 MW by 2050.

2.6.3 Technology Costs and Availability

Non-fuel operating costs are estimated based on published data and bid information.

Capital costs for thermal generation options are based on published data and industry knowledge. Existing clean coal technology such as Integrated Gasification Combined Cycle Plants (IGCC) and Ultra Clean Coal (UCC) are included as options in cost estimates. IGCC plant fitted with pre-combustion carbon capture and storage is also considered.

Carbon capture ready gas and coal plants were also considered, with carbon capture and storage technology not available until 2020[5].

Recently, the low rainfall level has affected the availability of some of the electricity generation assets, with lower than normal generation levels from hydro-electric facilities and some coal-fired plant being forced offline to manage water supplies. In this modelling, it is assumed that these coal-fired plants come back on line in 2008 and that generation from hydro-electric facilities return to normal levels over a 5 year period ending 2012.

Costs for renewable generation projects are derived from published sources of information. MMA maintains a database of renewable energy projects, which contains information on capacity, generation levels, operating costs, capital costs and other costs for

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5 Although in all scenarios modelled, this technology was not used until well after 2020 and in most cases not until after 2030.

each renewable generation project - operating, committed or planned. The location by sub-state region is also known, and incorporated into the model.

Real capital costs for all technologies are assumed to fall over time. A "capital cost reduction factor" is included for each technology in the analysis to model this effect, with the reduction factor specific to the technologies. For renewable technologies, Treasury provided additional renewable capital cost reduction factors that were applied in addition to the MMA ones. These were derived from the international modelling with GTEM and were imposed to capture greater learning by doing from greater international deployment of renewable technologies in the policy scenarios.

The commodity component of the capital cost for all technologies was indexed against global movements in metal prices as provided by the Treasury.

Future transmission and distribution prices are estimated from historical trends in prices and recent regulatory decisions on allowable movements in prices (under the CPI-X provisions). Network charges were assumed to increase by 5% real per annum until 2019, with this rate declining by 1% per annum until 2024 and then held constant.

Network upgrade costs are based on the Annual Planning Statements published by the State Jurisdictions and planning bodies. The data was used to make assumptions on the costs of both committed and planned interregional network upgrades.

2.6.4 Fuel prices

Projected fuel prices for both existing and new thermal generation were based upon MMA's database of current prices and movements in the international energy prices as provided by Treasury for each scenario. The former is based upon published data on prices (such as ABARE's export coal price projections) and published data on contract quantities.

Key feature of the assumptions are:

- Brown coal and mine mouth black coal prices were held constant at the current contract values in real terms.
- For existing black coal generators not at mine mouth, black coal prices were modelled as per contract prices until around 2017 when current contracts are due to expire. From this time there was allowance for new coal contracts to be influenced by international energy prices subject to a discount premium.
- New black coal plant fuel prices were aligned with the international coal price index.
- East coast gas prices were determined from MMA's gas model assuming moderate LNG penetration in Queensland. Prices at the Gladstone port were predicted to reach export parity in 2025 with the southern state prices converging with the Queensland price by around 2030.

- West cost gas prices were influenced by international price shifts from the beginning of the projection period.

Projected gas and fuel prices for new plant are given in Figure 2-3 and Figure 2-4.

Figure 2-3: Trends in city node gas prices, NSW

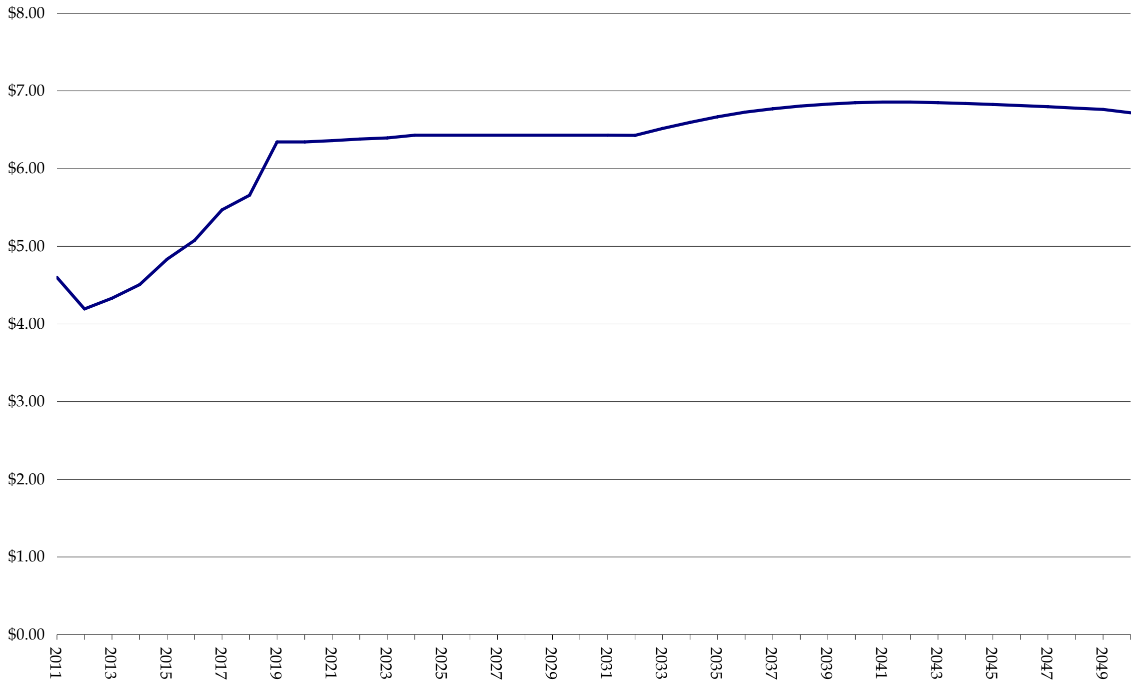
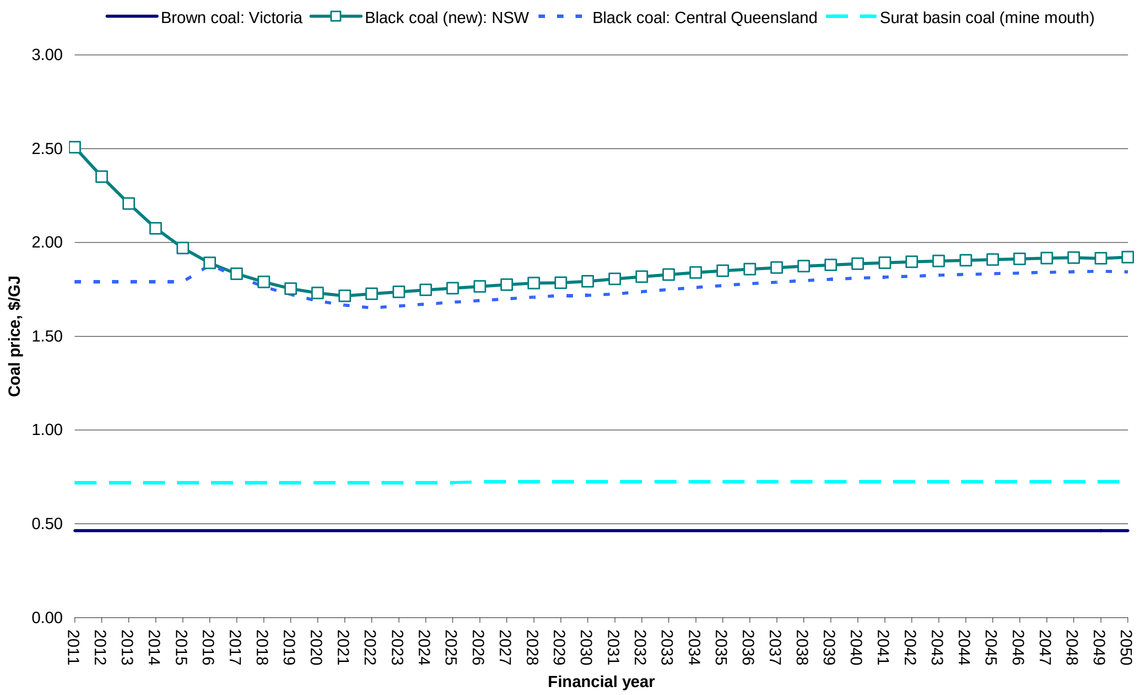


Figure 2-4: Trends in coal prices



2.6.5 Emissions

Greenhouse gas emissions per generating unit are estimated based on National Greenhouse Gas Inventory (NGGI) data on emission intensity per unit of fuel used.

2.6.6 Cost of abatement technologies

A key component of the analysis of the impact of abatement costs is the cost of abatement technologies.

Based on other analysis undertaken by MMA, about 700 MW of new capacity per annum is required across all regions of the NEM, SWIS and DKIS from about 2009/10 onwards. Not all this will be high load duty plant.

Over the next ten to fifteen years, assumptions on potential new base load options competing to supply the NEM include:

- Expansions at Kogan Creek Power Station, adding 700 MW coal-fired units
- Expansions at the Millmerran Power Station in south-west Queensland, adding 2 x 400 MW units
- New 700 MW coal-fired units in the Surat basin
- New coal-fired power plant, comprising 700 MW units to be located in the Hunter Valley or Western Downs region of NSW
- New 200 MW coal-fired units near the Collie coal fields in south west Western Australia
- New units in the Latrobe Valley of Victoria, utilising low cost brown coal and supercritical or ultra-supercritical pulverised fuel technology (with or without coal drying)
- New gas fired combined cycle plant to be located in any of the States.

In the longer-term, new technologies with low or no emissions are likely to be adopted. This includes IGCC technology using coal as a fuel and more efficient natural gas fired combined cycle plant. In this study, nuclear power generation was not considered.

MMA have developed a full financial model to derive the relationship between capital expenditure, fuel price and electricity price to achieve a required rate of return for the new base load plant. Input assumptions included in the analysis are:

- Economic life - 30 to 60 years operation
- Debt/equity ratio - 60%
- Loan period - 15 years

- Interest rate on loans – 7% pa

Levelised costs were derived by assuming a 9.22% WACC for the nominated coal or gas price range and capital cost estimates for each project.

Estimates of new plant costs were based on the following assumptions provided in published documents or discussions of experts. Key assumptions behind the analysis are listed in Table 2-1. This analysis is based on published documents and discussions with experts. The data are representative for plants in the NEM. Smaller plant sizes will be typical for the SWIS. For the SWIS, it is assumed that pulverised fuel coal fired plants are around 200 MW and IGCC technology are 240 MW. The smaller sizes come with a higher capital cost of about 10% above the estimates for the larger units. Efficiency is also assumed to be slightly lower.

Based on initial assessments some technologies were excluded from the analysis due to its high cost and the availability of lower cost competing alternative or the high uncertainty over the estimates of technical performance or cost. For example, new coal plant with post combustion capture technologies and new plant with oxy-firing technologies were not considered in the models.

The long-run average cost assumed for each technology is shown in Figure 2.2 for a capacity factor of 90%, while that at 50% is given in Figure 2-6. The trends indicate that current technologies are likely to remain the preferred option on cost grounds unless carbon prices are imposed.

Gas fired plants for base load duty, are likely to be of higher cost than for coal plant operating on base load duty in the absence of emissions trading. The principle cause for this is the assumed increase in gas prices expected to occur in the long-term as a result of increasing gas demand, the increasing cost of supply as a result of the need to source gas from more remote fields and the convergence of the eastern seaboard with export parity.

The long-run marginal cost curves represented in the charts below are indicative only. For each technology, the charts show the overall trends in costs for the least cost option for that technology. But as more of that technology is required, costs are assumed to rise to reflect the fact that the least cost options for each technology is likely to be adopted first. Thus, for example, as more black coal plant are required, the long-run marginal cost are likely to increase as more expensive coal sources are used and as transmission costs (higher marginal loss factors) to service the market are increased.

Table 2-1: Technology costs and performance assumptions, mid 2007 dollar terms

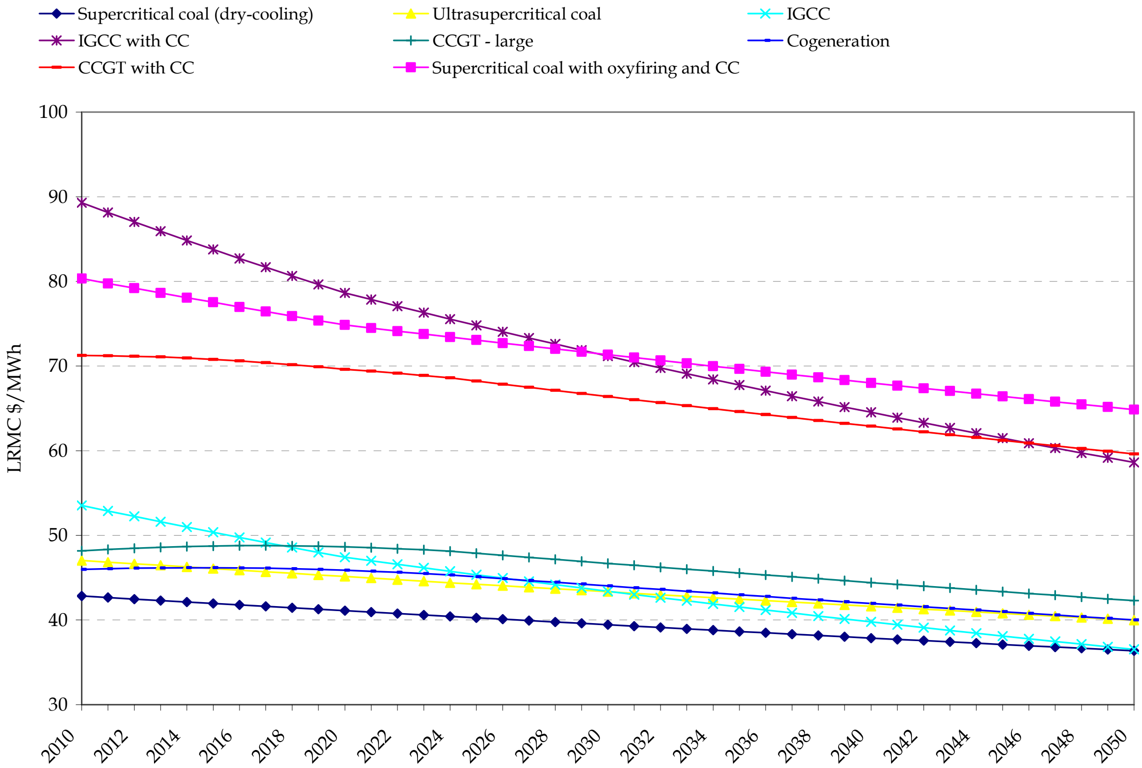
Option	Life	Sent-out Capacity	Capital Cost, 2010	Capital Cost Deescalater, 2010 to 2020	Capital Cost Deescalater, 2021 to 2030	Heat Rate at Maximum Capacity	Efficiency improvement	Variable Non-Fuel Operating Cost	Fixed Operating Cost
	Years	MW	$/kW so	% pa	% pa	GJ/MWh	% pa	$/MWh	$/kW
Black Coal Options									
Supercritical coal (dry-cooling)	35	690	1,879	0.5	0.5	9.6	0.48	3	30
Ultra-supercritical coal	35	690	2,255	0.5	0.5	8.7	0.48	3	38
IGCC	30	554	2,673	1.5	1.0	9.1	1.20	2	44
IGCC with CCS	30	473	3,688	1.5	1.0	11.4	1.30	3	50
Ultra-supercritical with CC and oxy-firing	35	525	2,997	1.0	0.5	12.0	0.58	3	39
USC with post-combustion capture	35	608	3,044	1.5	0.5	12.9	0.58	4	37
Brown Coal Options									
Supercritical coal with drying	35	636	1,972	0.5	0.5	10.3	0.48	5	43
Supercritical coal	35	665	2,289	0.5	0.5	10.8	0.48	5	35
Ultra supercritical coal with drying	35	636	2,366	1.0	0.5	9.8	0.48	5	43
IGCC with drying	30	375	2,788	1.0	1.0	9.8	1.20	4	49
IDGCC	30	416	2,732	1.5	0.5	9.8	1.20	6	60
IGCC with CCS and drying	30	360	3,886	1.5	0.5	11.4	1.30	5	55

Option	Life	Sent-out Capacity	Capital Cost, 2010	Capital Cost Deescalater, 2010 to 2020	Capital Cost Deescalater, 2021 to 2030	Heat Rate at Maximum Capacity	Efficiency improvement	Variable Non-Fuel Operating Cost	Fixed Operating Cost
	Years	MW	$/kW so	% pa	% pa	GJ/MWh	% pa	$/MWh	$/kW
IDGCC with CCS	30	380	3,026	1.5	0.5	10.4	1.30	5	70
Natural gas options									
CCGT - small	30	235	1,467	0.5	0.5	7.4	0.60	3	22
CCGT - small	30	47	2,054	0.5	0.5	7.8	0.60	4	25
CCGT - large	30	490	1,334	0.5	0.5	6.8	0.60	3	20
Cogeneration	30	235	1,740	0.5	0.5	5.0	0.60	3	20
CCGT with CCS	30	450	2,001	1.0	0.5	7.9	0.70	4	40
Renewable energy options									
Wind	25	99	2,134	0.5	0.5		0.20	2	35
Biomass - Steam	30	28	2,598	0.5	0.5	11.5	0.10	4	50
Biomass - Gasification	25	27	2,784	1.5	1.0	11.0	0.10	5	50
Concentrated Solar thermal plant	20	99	4,176	1.5	1.0				50
Geothermal - Hot Dry Rocks	25	45	4,200	1.5	0.5	12.0	0.10	3	70
Concentrating PV	30	97	4,640	1.0	1.0		0.10		
Hydro	35	30	2,320	1.0	0.5	3.6	0.05	3	35

Note: Plant capacity, efficiency and cost data based on a sent out basis. The efficiency improvements occurred up to a technical limit for each technology. For example, the efficiency of CCGT technology was constrained to a maximum of 60%. Similarly, the efficiency of supercritical coal technologies were limited to a maximum of 50%. The capital cost deescalates for the renewable energy technologies are a guide only, with the numbers used provided by Treasury and changing per scenario.

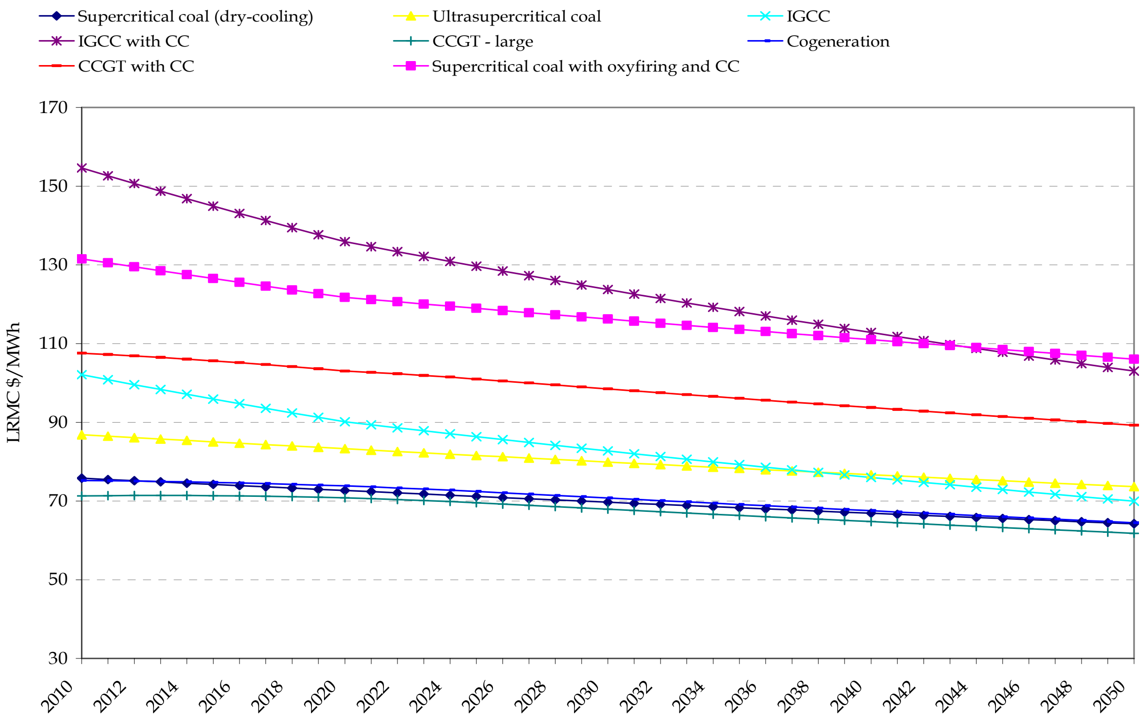
Sources: EPRI (2006), IPCC (2006), IPCC (2008), IEA (2005), IEA (2007), I. Ekeda et.. al. (2007),, CO2CRC (2007),, Solar Systems, Sergeant and Lundy (2003),, personal communication with generators.

Figure 2-5: Trends in long-run costs for generating technologies, NSW, $/MWh



Note: Levelised costs calculated using the assumptions listed in the text above and for a capacity factor of 90%. CCS costs do not include the cost of transport and storage, which vary by state and over time.

Figure 2-6: Trends in long-run costs for generating technologies, NSW, $/MWh



Note: Levelised costs calculated using the assumptions listed in the text above and for a capacity factor of 50%. CCS costs do not include the cost of transport and storage, which vary by state and over time.

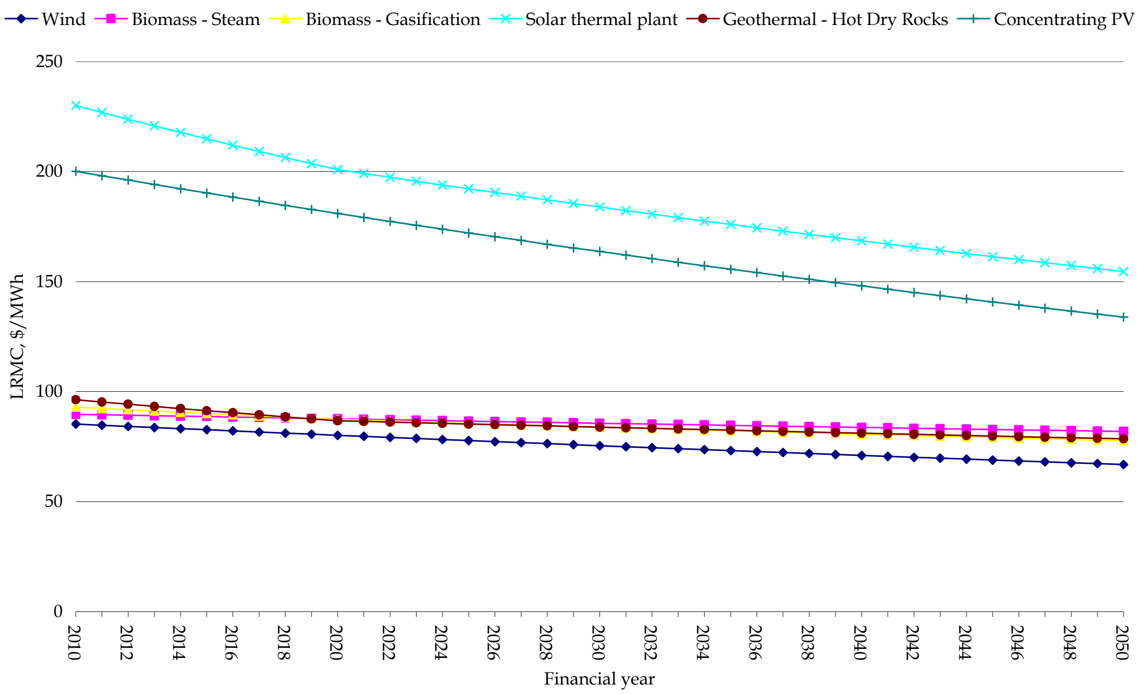
2.6.7 New generation costs – renewable generation

Renewable generation costs were based on data published in previous MMA reports. The key assumptions are shown in Table 2-1.

Small scale (distributed or roof-top) PV generation was not considered in the analysis, because its high costs meant significant market penetration was unlikely. However, larger PV systems were considered. The cost of PV generation is projected to decline to around $120/MWh by 2030, which makes it comparable to retail cost of electricity to small customers such as domestic residences and shops. However, the number of customers switching to PV will be limited as they will still need to incur a high proportion of network costs[6], which will only be partly compensated by sales of energy to the grid.

Further, the amount of renewable generation able to be bid into the market was also limited as generation costs would be expected to rise above those shown above as wind farms were located in more remote or less windy areas and as biomass plant sources more remote fuel. The total amount of commercially accessible new renewable generation resource was limited to 132,429 GWh and 224,437 GWh above current levels by 2030 and 2050 respectively. The limitations on new renewable capacity were based upon previous analysis undertaken by MMA and take into consideration system constraints in absorbing intermittent technology such as wind. A conservative constraint on the success on geothermal was employed, with the total capacity restricted to approximately 12,000 MW by 2050.

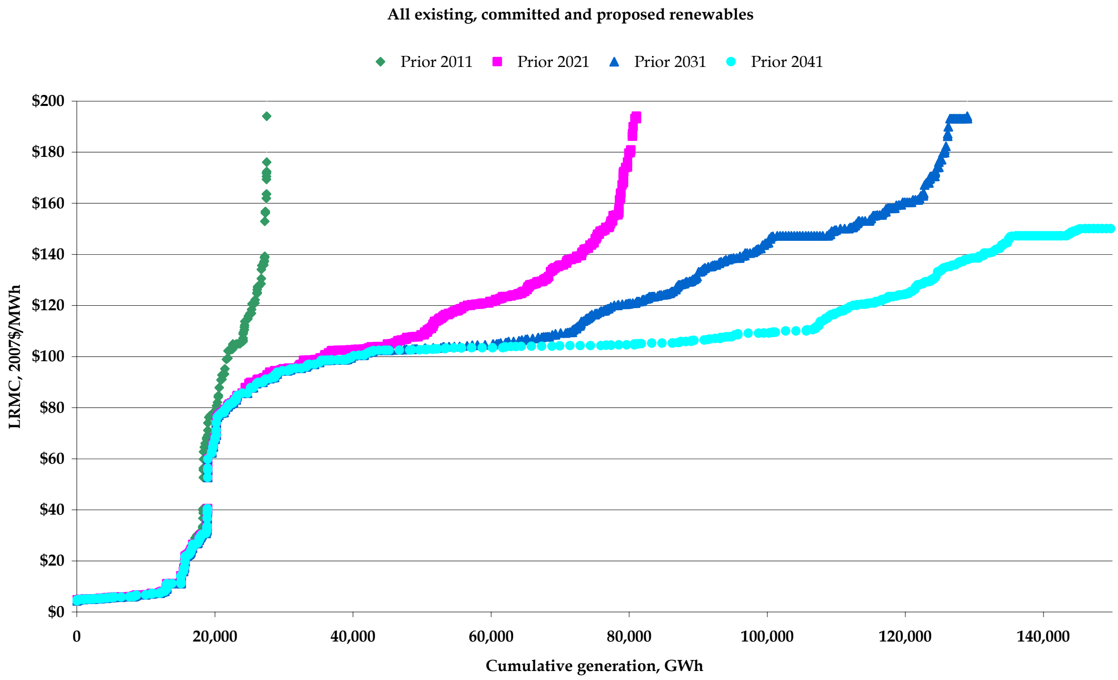
Figure 2-7: Trends in long-run costs for renewable energy generating technologies, NSW, $/MWh



[6] Network costs are considered fixed costs and to be paid regardless of the use of the network.

As with fossil fuel technologies, the long-run marginal cost of renewable energy generation increases as more of each technology is required. For example, less windy sites will be accessed as more wind generation is required. Fuel costs will increase as more biomass options are required. Assumptions on the marginal cost curve as a function of level of generation required are shown in Figure 2-8.

Figure 2-8: Long-run marginal cost for renewable energy generation in Australia



2.7 Scheme Coverage and Scenarios

To model the impact of an Australian ETS in the global environment, several scenarios were constructed:

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

- **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.

- **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.

The implications and restrictions of these scenarios on the electricity sector differ for all, with the key assumptions relevant to the modelling summarised in Table 2-2. The Reference case retains the existing MRET and VRET policies with the accompanying GreenPower scheme, and also includes the Queensland and New South Wales abatement schemes. These two State schemes are modelled to continue to 2020, at which point they cease with no phase out. The two Garnaut cases see the ETS start in July 2013, with all other policies ceasing upon the onset of trading. The remaining ETS scenarios see a carbon price operational from 2010, retain the Qld GEC scheme but abolish the NSW policy. The expanded RET is considered in the CPRS -5 and CPRS - 15 scenarios.

Table 2-2: Scenario assumptions for the electricity sector

Scenario	ETS start year	Renewable Schemes	Qld GEC end date	NSW GGAC end date
Reference	N/A	Existing MRET, VRET. Green Power	2020	2020
Garnaut -10	July 2013	Existing MRET, VRET and Green Power ceasing in 2013	2013	2013
Garnaut -25	July 2013	Existing MRET, VRET and Green Power ceasing in 2013	2013	2013
CPRS Only	July 2010	Existing MRET, VRET and Green Power .	2020	2010
CPRS -5	July 2010	RET and Green Power	2020	2010

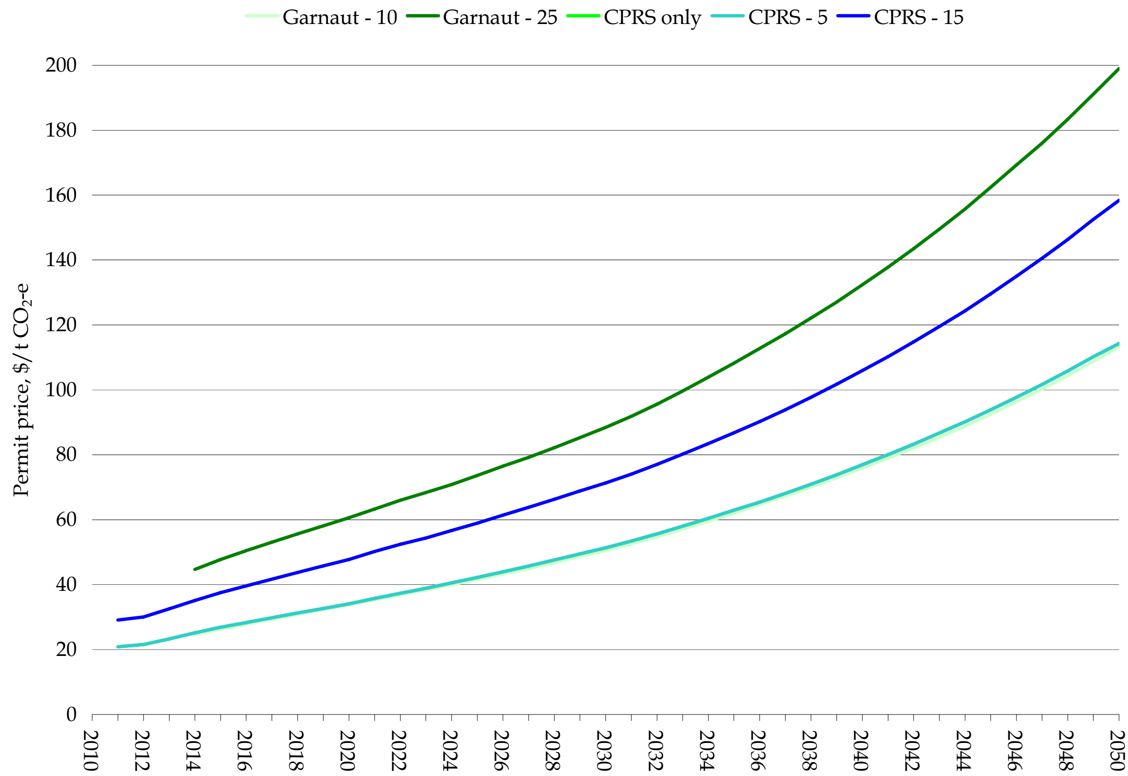
The following further assumptions were employed:

- Scheme coverage was confined to full fuel cycle emissions from electricity generation with fugitive emissions also covered

- There were some restrictions on emissions abatement options (for example, nuclear energy was excluded)

- As the permit price trajectory was provided by Treasury, banking was not explicitly modelled in the electricity sector. Rather the permit price encouraged the level of abatement. Permit prices were derived from economy wide modelling and these were used as an input into the electricity market simulations. The permit prices used are shown in the following chart.

Figure 2-9: Permit prices, $2007



3 COSTS TO THE GENERATION SECTOR

3.1 Overview

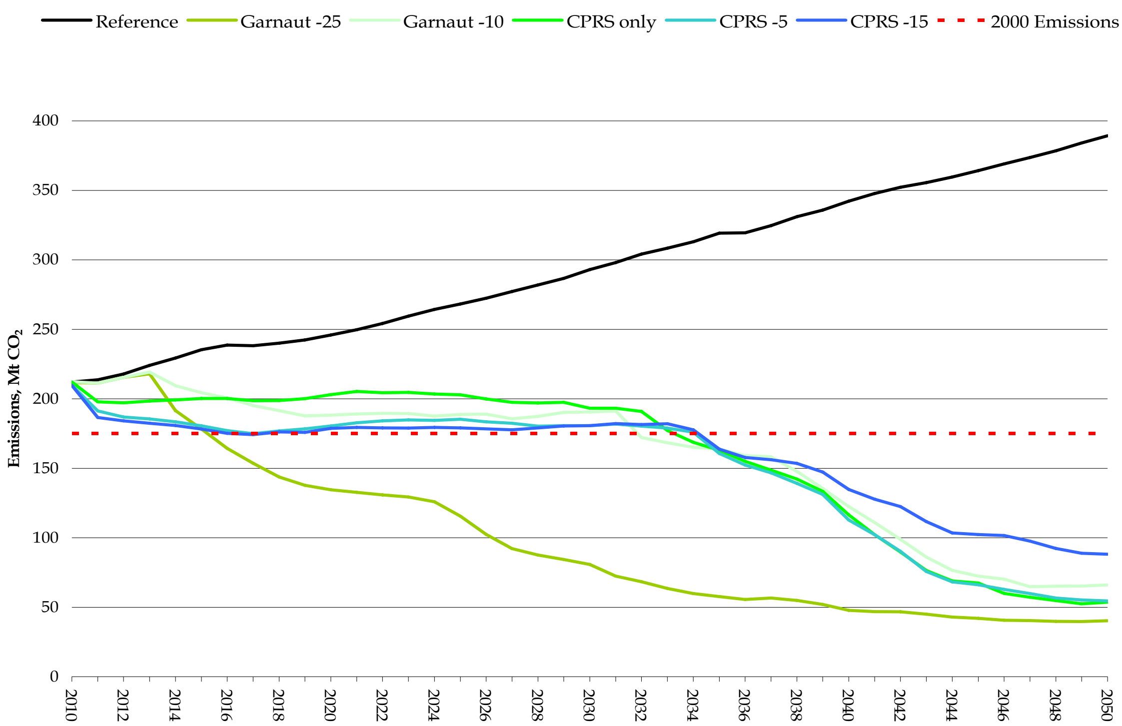
Emission trading is designed to reduce the amount of emissions of greenhouse gases. This is done by increasing the cost of activities with high emission rates, and driving investment in or uptake of lower emissions technologies and activities. As low-emission technologies and fuels can be more expensive than those used currently, (or under business as usual), emissions trading results in some cost to the economy.

3.2 Abatement - Australia

The level of abatement achieved in the electricity sector depends intrinsically on the carbon price and the complementary policies that are operational. As the scenarios were modelled with a permit price trajectory, the banking of permits to achieve a specific abatement target in the sector was not considered. Rather, measures such as the RET increase the level of abatement in the sector.

Combined emissions from combustion of fuels in electricity generation are shown in Figure 3-1. In all scenarios with emissions trading, emissions are expected to be well below the level projected without the scheme.

Figure 3-1: Emissions from electricity generation, Mt CO_2



Emissions in the reference case grow steadily across the entire projection period, nearing 400 MT CO_2 by 2050, growing at an average of 1.5% per annum. The growth is driven by the large demand increase which is met by conventional coal and gas fired generation.

Emissions in the scenarios with emissions trading depend on the permit price as the overall target is set for the economy as a whole. The level of abatement across the sectors of the economy depends on the relativity of the marginal cost of abatement for each sector. Therefore, even if there is a economy wide cap of, say, 5% below 2000 levels by 2020, some sectors with low cost abatement options may achieve more than 5% reduction and other sectors with high costs of abatement may achieve less. In addition, the availability of low cost permits sourced from other countries with large amounts of low cost abatement.

This is demonstrated in the results for the electricity generation sector, where only in one scenario do emissions actually fall below 2000 levels by 2020. For most scenarios, there is an initial fall in emissions but then emissions stabilise until the 2030's, when other low cost sources of abatement are commercialised and permit prices are high enough to make these new sources of abatement economic.

Cuts in emissions relative to 2000 levels for each scenario are shown in Table 3-1. The key feature is that by 2020, emissions are equal to or up to 16% above 2000 levels for CPRS -10, CPRS -5 and CPRS scenarios. Only in the Garnaut –25 scenario do we get a substantial reduction below 2000 levels. For most scenarios, emissions are still above 2000 levels even in 2030. But after 2030, there is a fast drop in emissions so that for most scenarios emissions are at least 60% below 2000 (and no more than 55% of 1990 levels).

Table 3-1: Emissions in electricity generation

	2020	2030	2040	2050
Emissions, Mt				
2000 level	175	175	175	175
Garnaut -25	134	81	48	40
Garnaut -10	188	191	123	66
CPRS only	203	193	116	54
CPRS -5	180	181	113	55
CPRS -15	179	181	135	88
Change from 2000 levels				
Garnaut -25	-23%	-54%	-73%	-77%
Garnaut -10	8%	9%	-30%	-62%
CPRS only	16%	10%	-33%	-69%
CPRS -5	3%	3%	-36%	-69%
CPRS -15	2%	3%	-23%	-50%

The Government's proposed expanded renewable energy target allows for greater cuts in emissions in the near term, causing emissions to stabilise at 2000 levels by 2020. Emissions are some 30 Mt pa lower in 2020 as a result of this measure.

The Garnaut -25 scenario (with 25% cuts in emissions) results in the deepest cuts, leading to cuts in emissions relative to the reference case of around 125 Mt in 2020.

Figure 3-1: Cumulative emissions

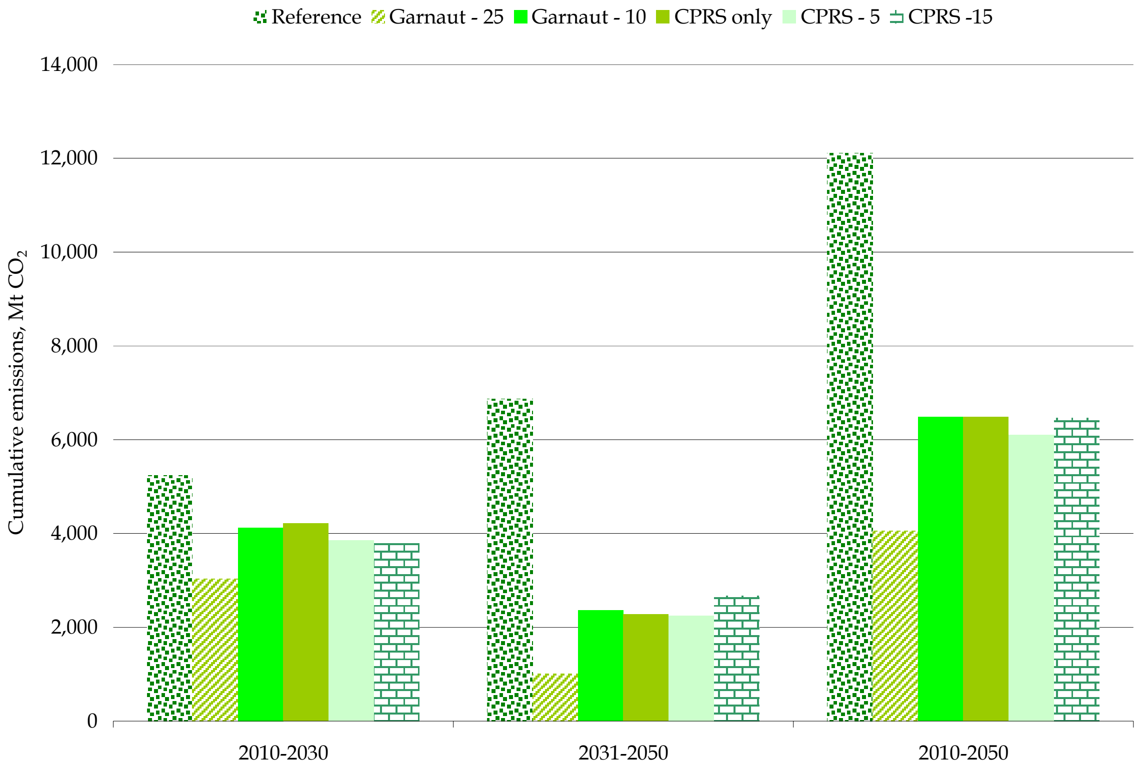
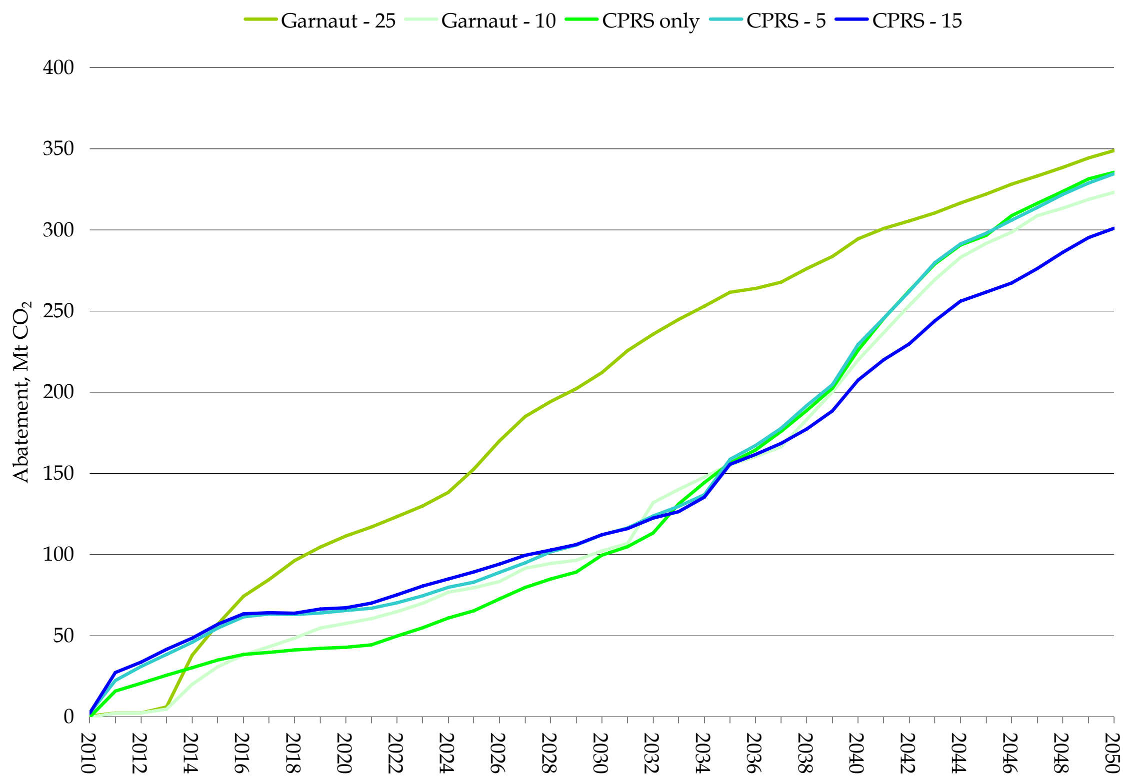
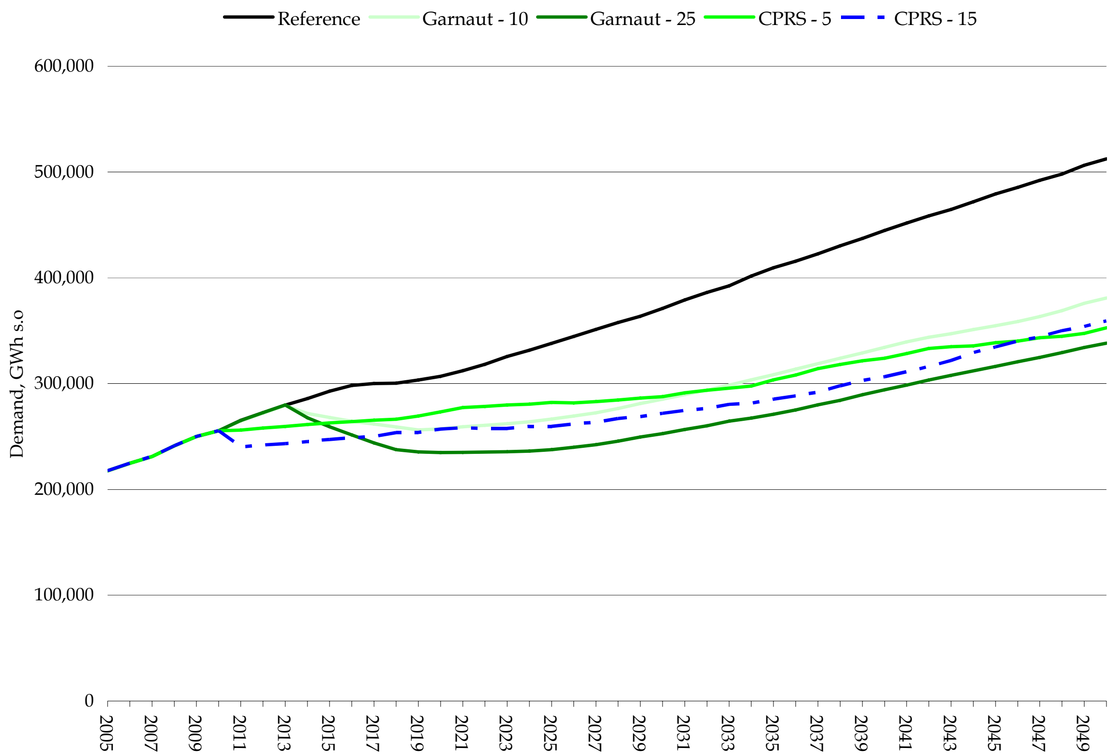


Figure 3-2: Abatement in the electricity generation sector, Mt CO_2



Three factors are responsible for the rate of change in emissions for the given permit prices. First, there is the response of electricity demand to the higher electricity prices wrought by emission trading[7]. With the onset of emission trading, electricity demand either stabilises or falls slightly before recovering to grow at a slower rate than for the reference scenario (see Figure 3-3). By 2020, electricity demand is some 11% to 23% below reference case levels and by 2050, demand is some 23% to 34% below reference case levels (see Table 3-2).

Figure 3-3: Electricity generation, GWh sent out basis



The second factor is the switch away from coal-fired generation from incumbents to gas-fired generation and renewable energy generation, which is a function of gas prices and permit prices. In most emission trading scenarios, the level of black coal and brown coal generation decreases by a greater amount than the decrease in demand. The reduction in coal fired generation is replaced by higher levels of renewable generation and natural gas fired generation, both of which have lower emission intensities.

7 The response of demand to higher electricity prices were determined by the MMRF model through an iteration process with MMA's Stategist model, which provided the wholesale price rises. 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.

Table 3-2: Change in electricity demand

	2010	2020	2030	2040	2050
Generation (sent out basis), TWh					
Reference	255	307	371	445	512
Garnaut -10	255	257	285	334	381
Garnaut -25	255	235	253	294	338
CPRS only	255	272	293	339	390
CPRS -5	255	272	293	339	392
CPRS -15	255	272	290	328	386
Change from reference case					
Garnaut -10		-16%	-23%	-25%	-26%
Garnaut -25		-23%	-32%	-34%	-34%
CPRS only		-12%	-21%	-24%	-24%
CPRS -5		-12%	-21%	-24%	-23%
CPRS -15		-11%	-22%	-26%	-25%

Figure 3-4: National generation mix, 2020

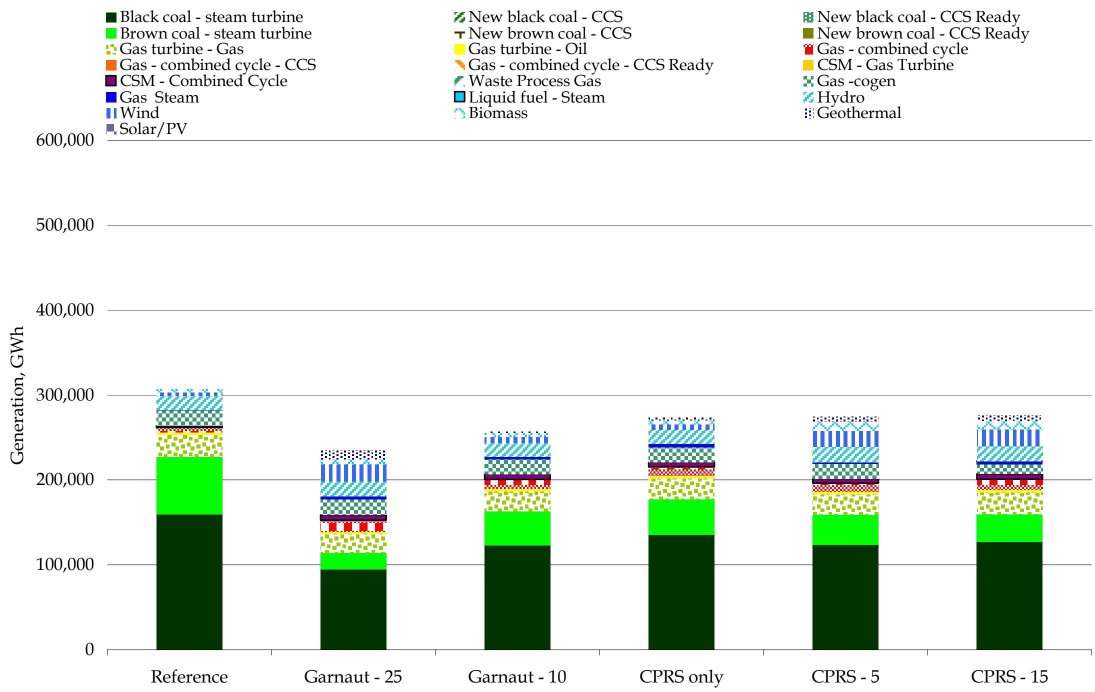


Figure 3-5: National generation mix, 2030

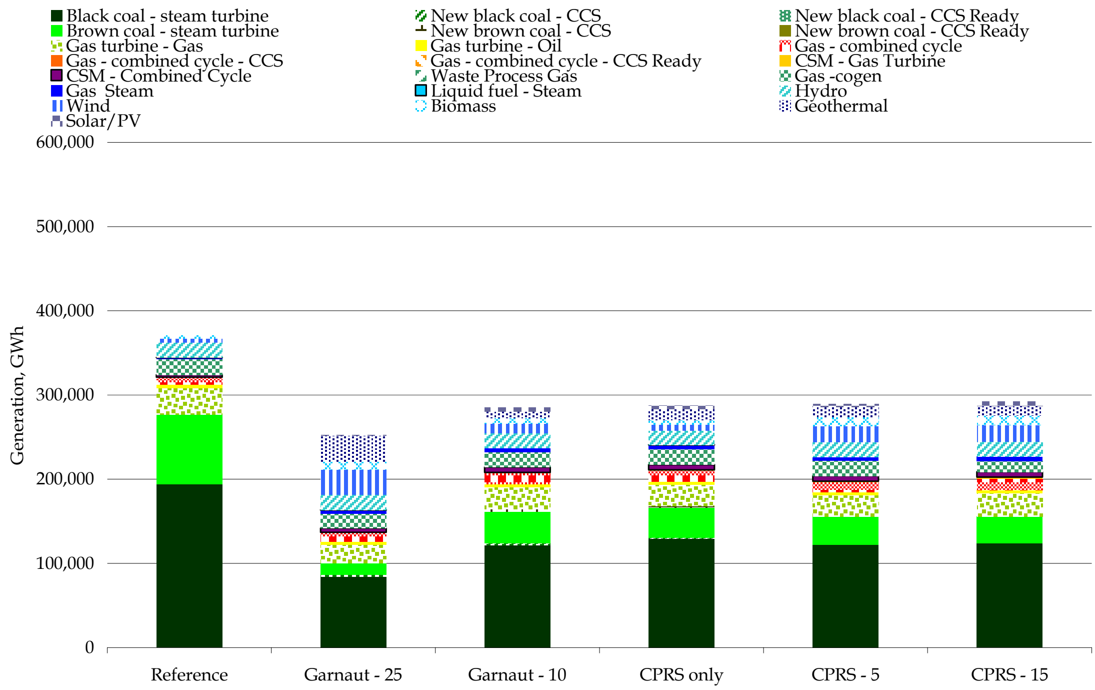
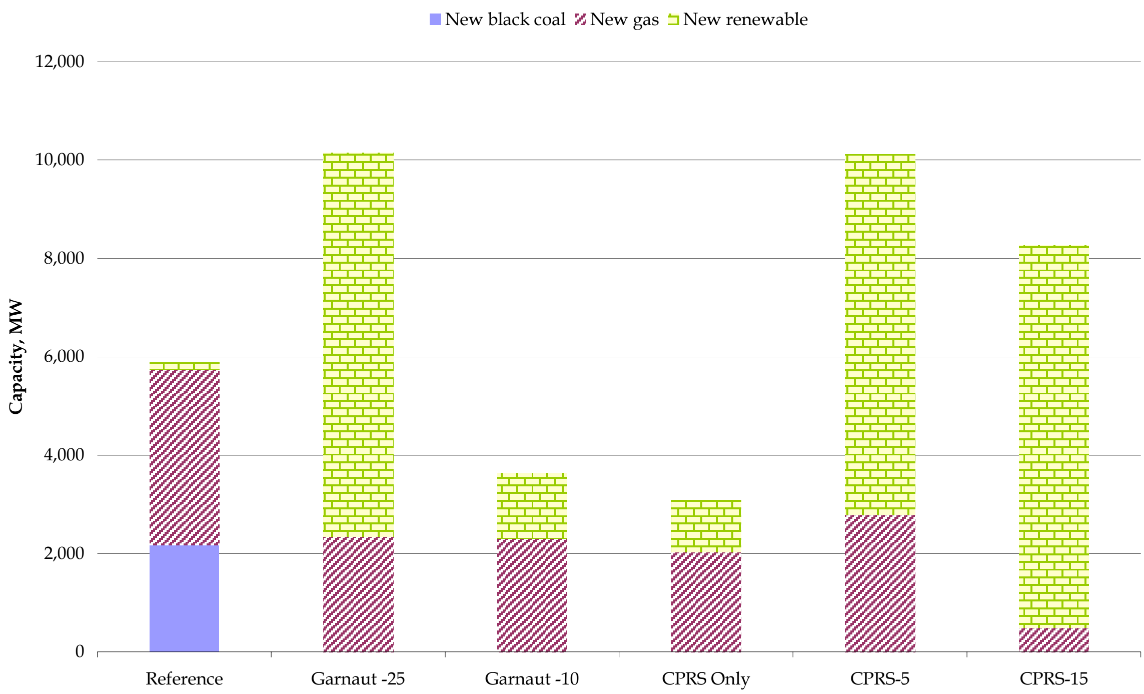


Table 3-3: Change in generation mix, 2020

	Reference	Garnaut - 25	Garnaut - 10	CPRS	CPRS -5	CPRS -15
Generation (sent out basis), TWh						
Black coal	160	94	123	135	123	127
Brown coal	67	20	41	42	36	33
Natural gas	52	64	60	62	59	59
Liquid fuels	3	3	3	3	3	3
Hydro-electric	17	18	17	16	18	18
Other renewable energy	8	36	13	14	36	36
% change from reference case						
Black coal		-41%	-23%	-15%	-23%	-20%
Brown coal		-70%	-39%	-37%	-47%	-52%
Natural gas		22%	16%	20%	13%	14%
Liquid fuels		-6%	-6%	0%	-2%	2%
Hydro-electric		6%	3%	0%	9%	7%
Other renewable energy		356%	63%	76%	352%	360%

The third factor is the change in the mix of new generation. In the reference case, around 2,200 MW of new coal plant is predicted to be brought on line by 2020 (mostly after 2015). However, in all the emission trading scenarios modelled, no new coal plants are brought on line in the period to 2020. New gas plant are brought on line even in the reference case where the growth in peak demand causes the need for additional peaking plant and because government support policies (NSW Greenhouse Gas Abatement Scheme and Queensland GEC Scheme) support low emission generation. In the emission trading scenarios, new gas fired plants are also brought on stream but at slightly lower levels due to the lower demand growth. Significant additions of new renewable generation are also required especially where the expanded MRET is included.

Figure 3-6: New capacity requirements in major grids from 2010 to 2020



3.3 State level abatement

State level abatement activity is shown in Table 3-4. As expected, Victoria has the largest abatement due to it being the location of the highest emission intensive generation. The abatement in this state is due to reduced demand, the early retirement of existing brown coal generating plant, offloading of the remaining coal-fired plant, deferment of new brown coal generation plant[8] and addition of renewable generation capacity.

NSW and Queensland also experience high rates of abatement. The high levels of abatement occurs because these states experience proportionally more of the demand decrease than other states and have relatively higher penetration of renewable energy (in

[8] In the reference case, new brown coal plant are required by 2013. In the emission trading cases, no new investment in brown coal plant occurs until the late 2020s, after carbon capture and storage has become available.

the form of geothermal and solar thermal) generation in the long-term. These factors help to displace black coal fired generation in these states.

Western Australia also has high levels of black coal fired generation in the reference case. But abatement is muted in the emission trading cases because of the high gas price in that State, which means that a relatively high permit price is required to cause any fuel switching. Because of the limited size of the grid and its isolation from other electrical networks, the penetration of wind generation is also limited in the medium-term.

Figure 3-7: Average annual abatement by State 2010-2050, Mt CO_2[9]

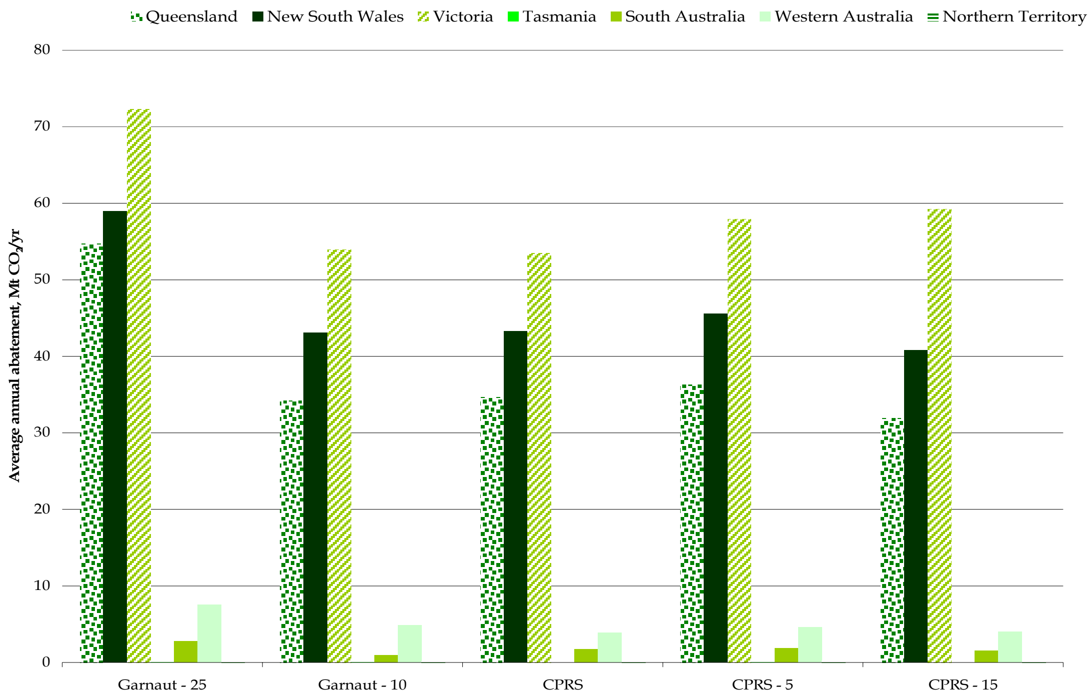


Table 3-4: Abatement by State, average annual abatement from 2010 to 2050

	Garnaut -25	Garnaut -10	CPRS Only	CPRS -5	CPRS -15
Queensland	54.7	34.2	34.7	36.3	31.9
New South Wales	58.9	43.1	43.3	45.5	40.8
Victoria	72.3	53.9	53.5	57.9	59.3
Tasmania[10]	0.0	0.0	0.0	0.1	0.0
South Australia	2.8	1.0	1.8	1.8	1.5
Western Australia	7.6	4.9	3.9	4.6	4.0
Northern Territory	0.2	0.2	0.2	0.2	0.1
Total	196.5	137.3	137.3	146.5	137.7

9 Note, although the emission trading in the Garnaut -10% and Garnaut -25% scenarios does not begin until 2013, abatement has been calculated here from 2010. Emission trading imfluences the choice of generation and plant mix in the years prior to its commencement, and thus there is positive abatement here.

10 Tasmania experiences a small increase in abatement in some scenarios as lower demand leads to less efficient operation of existing gas-fired plant in some years.

3.4 Cost of abatement

Abatement of greenhouse gases comes at a cost to the economy due to the fact that higher cost forms of generation are deployed to meet the emission targets.

Predicted trends in resource costs are shown in Figure 3-8 and Figure 3-9. The resource costs cover the cost of fuel, operating and maintaining plant and the capital costs of new plant.

Under emission trading, resource costs in electricity generation are actually equal to or slightly lower than in the reference case in the period to 2025. This is due to the decrease in demand under emission trading, which reduces the need for resources in electricity generation. In some emission trading scenarios, this is offset by the higher capital cost of new low emission generation. This does not mean that economic costs are low, rather the costs are borne by other sectors of the economy (partly reflected in the electricity sector as less efficient use of resources in other sectors lead to a reduced demand for electricity).

Over the long-term resource costs are significantly higher than in the reference case. By 2040, resource costs are about $4 billion to $8 billion per annum higher than in the reference case. By 2050, resource costs are estimate to be between $8 billion to $11 billion higher than the reference case. The higher cost is mainly due to the higher capital cost of new low emission plant and the additional cost of carbon capture and storage.

Figure 3-8: Resource costs – Garnaut scenarios

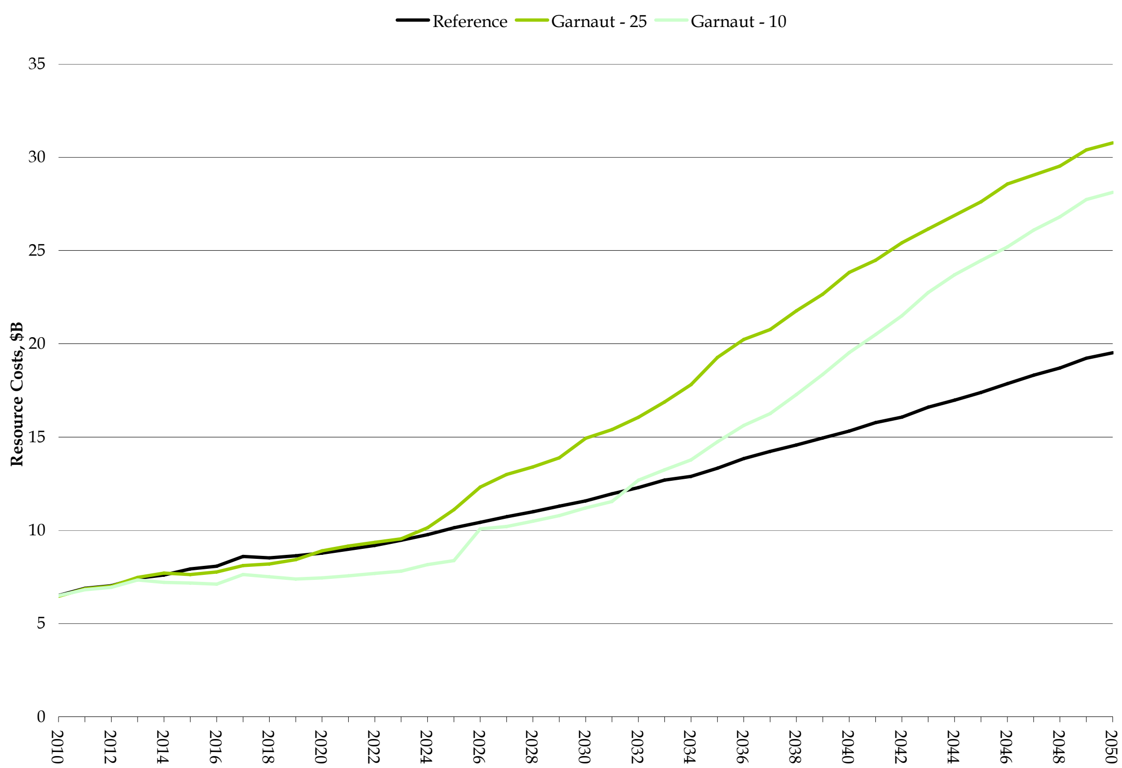


Figure 3-9: Resource costs: CPRS scenarios

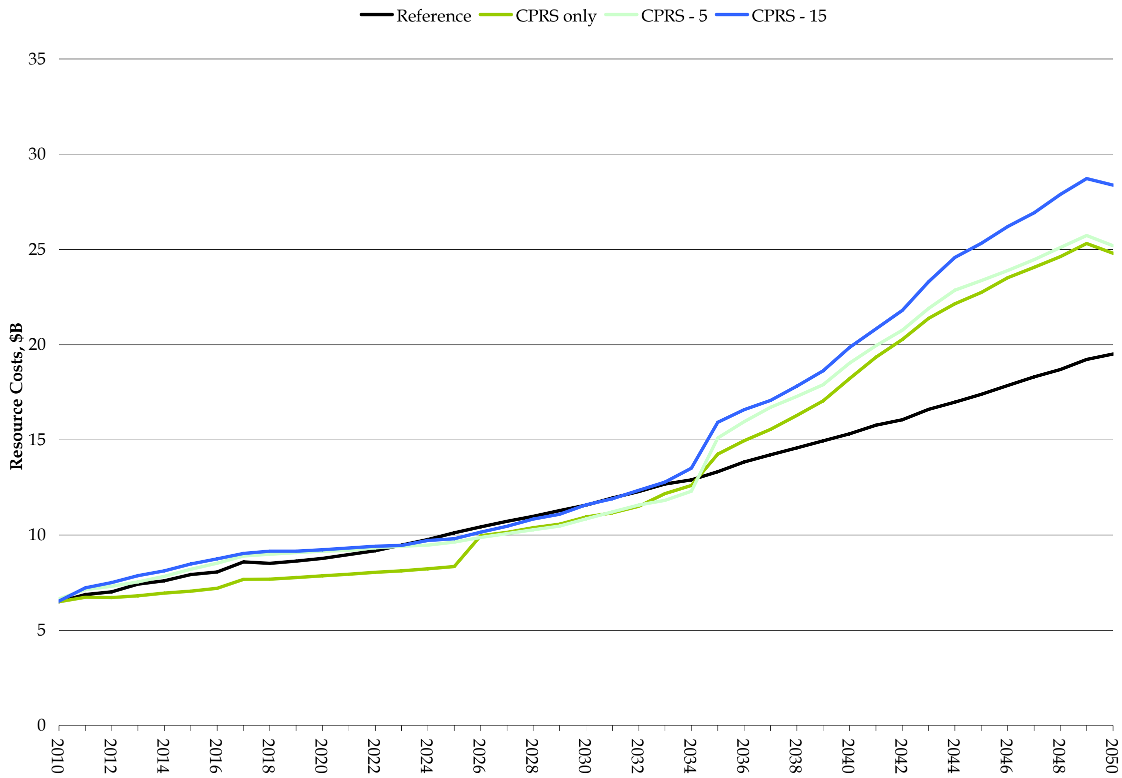
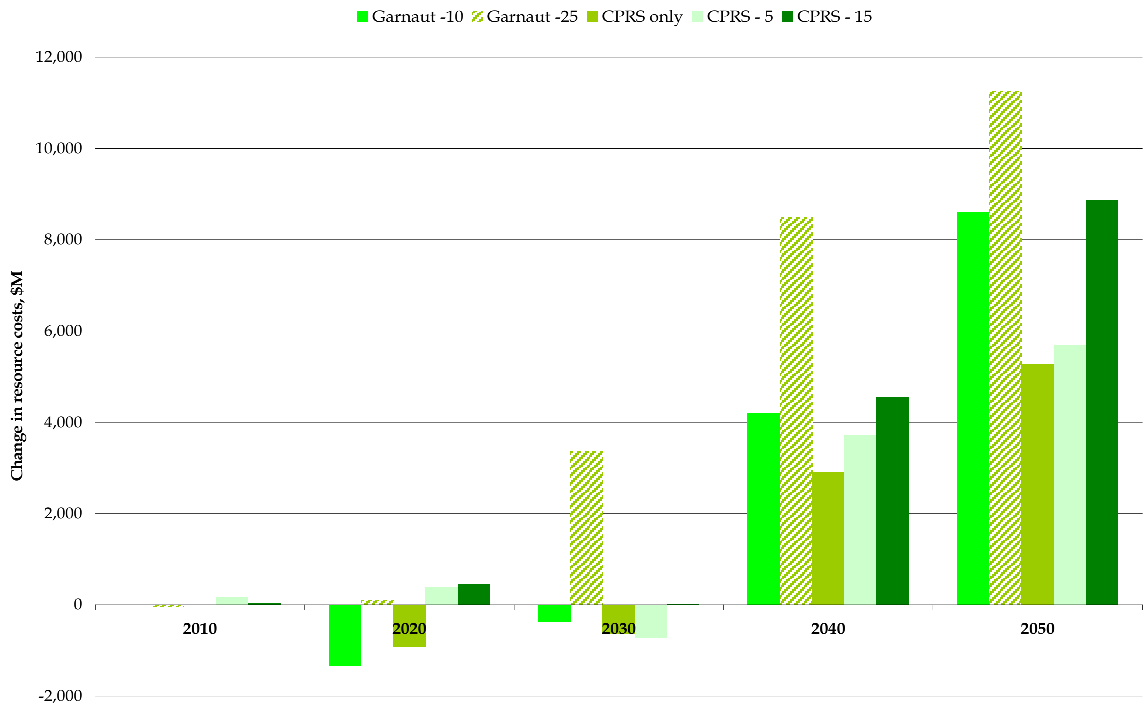


Figure 3-10: Change in resource costs relative to reference case



4 ELECTRICITY MARKET IMPACTS

4.1 Energy prices

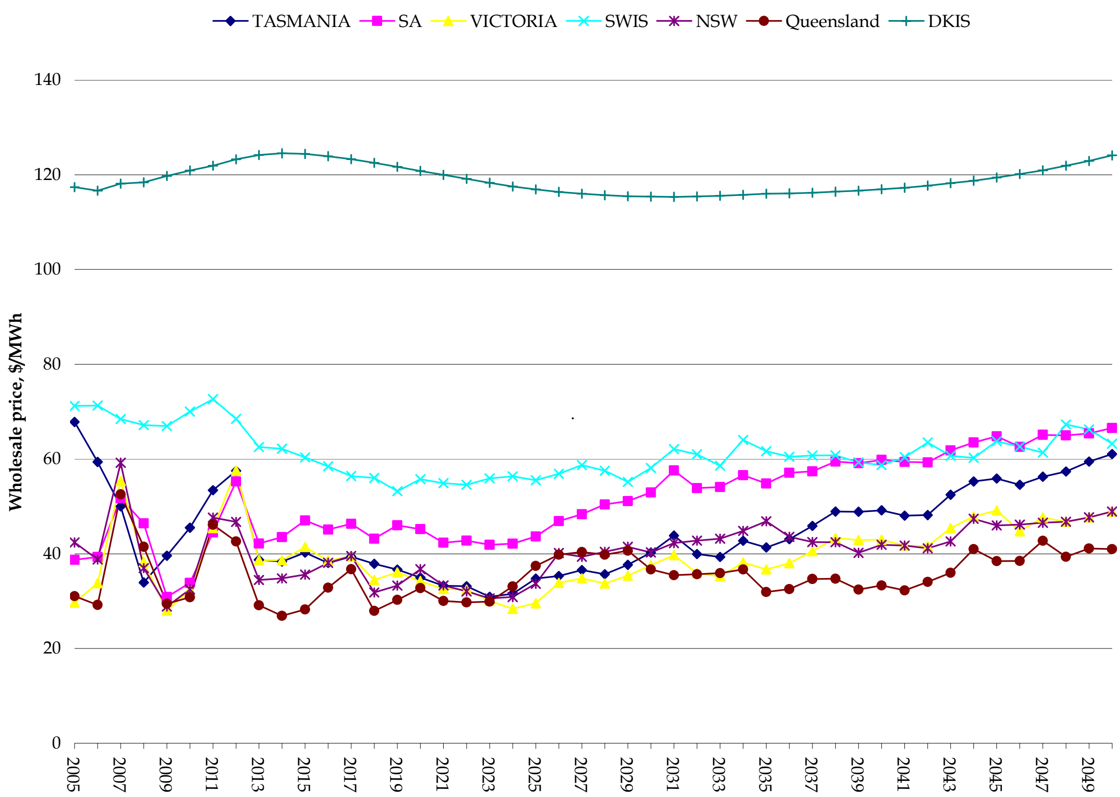
4.1.1 Reference case

Wholesale prices under an emission trading scheme are impacted by the permit price, changes in demand profile and level of demand and the cost of low emission generation technologies.

To compare impacts of emission trading, wholesale prices for the reference case are provided in Figure 4-1. The reference case contains a number of features that are likely to impact on price trends:

- Changes to gas and coal prices, which put downward pressure on prices in the period to 2025, but then force prices as the fuel costs increase.
- Inclusion of the NSW Greenhouse Gas Abatement Scheme and the Queensland Gas Electricity Certificate Scheme, both of which subsidises low emission generation and puts downward pressure on prices. Based on MMA analysis, NGAC prices which provide a subsidy on low emission generation in the NEM are predicted to increase from $14/certificate in 2010 to $20/certificate in 2020, amounting to a subsidy of between $8/MWh to $12/MWh.

Figure 4-1: Wholesale electricity prices, reference scenario



Prices in the NEM in the reference case rise from around $40/MWh to $45/MWh in the coal dominated states in the period to 2050. In other states prices rise to about $50/MWh on the back of rising gas costs. Prices in the SWIS are predicted to vary around $60/MWh, higher than in the NEM due to higher fuel costs and smaller scale of generation. Prices are in the DKIS in the Northern Territory move in line with international gas prices, hovering around $120/MWh.

Retail prices in the reference case change from current levels for two reasons. First, changes in wholesale prices are assumed to flow through to retail prices. Second, network costs are assumed to increase by around 5% per annum in real terms until 2024 (when the peak demand starts to move in line with average demand). While the wholesale price will change with emission trading, network charges are assumed to be the same under emission trading as for the reference scenario.

4.1.2 Wholesale prices

Average wholesale prices for Australia under emission trading are shown in Figure 4-2. As expected, wholesale prices move in line with permit price. The higher the permit price, the higher the wholesale price, although the relative increase diminishes as permit prices increase. Implementation of a renewable energy target can decrease prices up to around 10% in the short-term due to excess generation capacity entering the market, but has little impact on prices in the long-term as renewable energy is taken up under the emission trading scheme.

Figure 4-2: Wholesale electricity prices (time weighted average), Australia, $/MWh

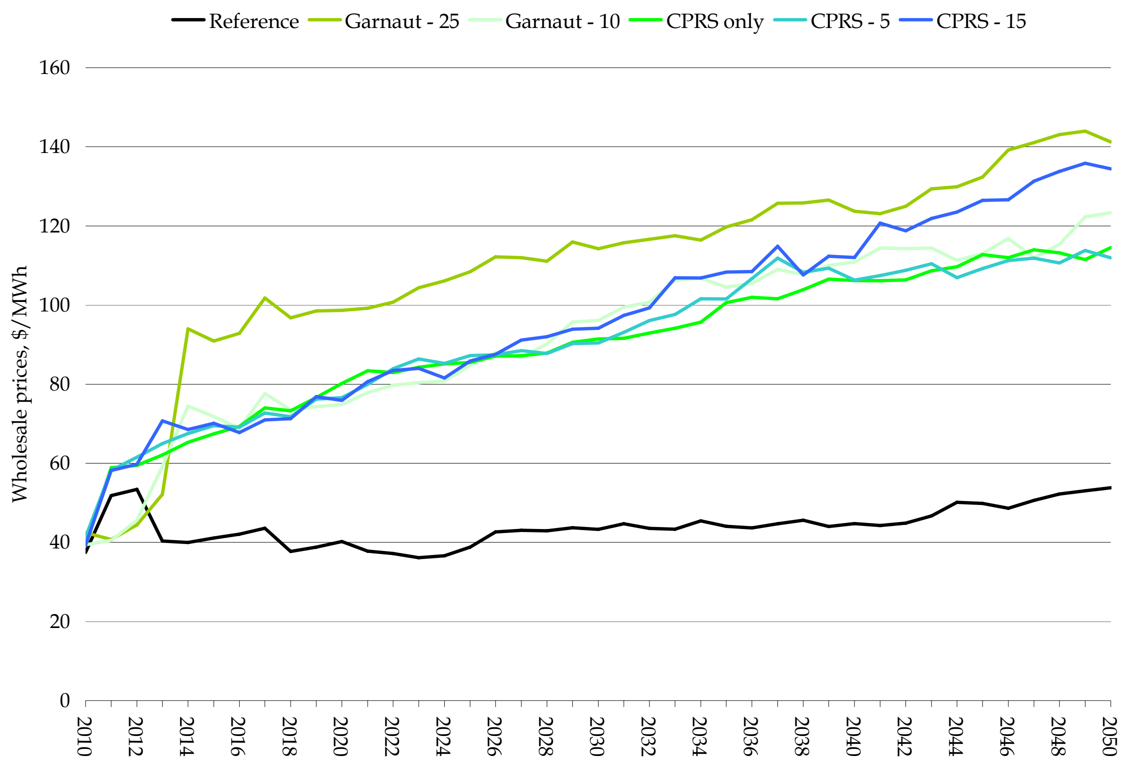
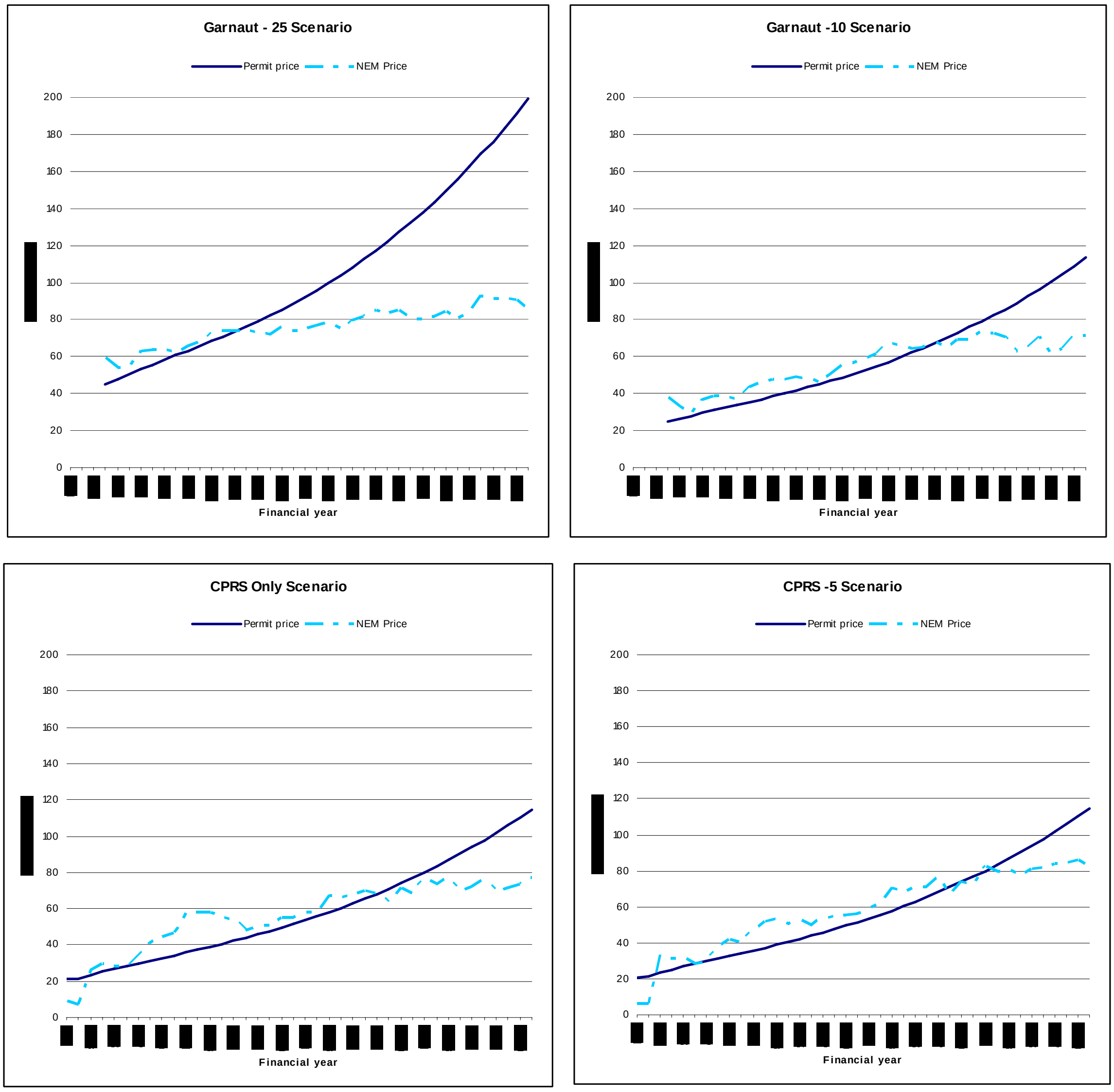


Table 4-1: Wholesale price increase relative to Reference case

	Garnaut -25			Garnaut -10			CPRS only			CPRS -5			CPRS -15		
	2010-2020	2021-2030	2031-2050	2010-2020	2021-2030	2031-2050	2010-2020	2021-2030	2031-2050	2010-2020	2021-2030	2031-2050	2010-2020	2021-2030	2031-2050
Change from Reference, $/MWh															
Queensland	38	61	78	22	40	69	23	42	60	23	42	63	23	42	70
New South Wales	37	72	86	24	46	69	26	48	60	27	49	61	28	51	76
Victoria	42	90	97	24	62	68	27	63	70	28	63	70	28	68	86
Tasmania	34	75	70	17	52	49	22	54	50	20	51	49	22	59	64
South Australia	36	65	63	26	54	55	26	44	34	24	43	41	24	46	62
Western Australia	21	50	71	11	29	51	14	28	52	15	27	53	11	16	46
Northern Territory	15	47	95	5	22	42	12	20	32	11	18	31	14	22	38
% Change from Reference															
Queensland	126	174	215	75	114	191	75	120	165	76	121	176	77	121	193
New South Wales	105	202	195	69	129	156	73	134	137	75	139	138	78	143	172
Victoria	161	275	230	66	190	163	71	193	166	75	193	165	76	208	203
Tasmania	94	215	144	48	150	102	60	156	103	54	147	103	58	168	133
South Australia	81	142	105	58	117	92	57	97	57	54	94	69	53	99	103
Western Australia	38	88	114	19	51	82	25	50	84	25	49	85	18	28	74
Northern Territory	12	40	215	4	19	35	10	17	27	9	16	26	12	19	29

A feature of the results is the fact that increase in \$/MWh terms is greater than the increase in the permit price for an extended period up to 2025 to 2035, implying that plant with a marginal intensity of greater than 1 are setting the price in the market. This occurs because of high price increases in the NEM, particularly in Victoria.

Figure 4-3: Wholesale price changes in the NEM (relative to reference case)



There are several factors that explain the high increase in electricity prices in these simulations:

- In the period to 2020, wholesale prices in the reference case are dampened by the presence of subsidies from the NGGAS scheme, under which low emission generator can earn revenue from generating certificates from eligible sources of generation. The certificates provide a revenue stream which generator use to subsidise dispatch in order to get the required level of generation. Because this scheme is assumed to expire with emission trading, this subsidy is removed. Emission trading effectively removes the subsidy and then adds a price impost in the form of permit prices

- Second, in this analysis fugitive emissions are included. Purchasing permits to cover the cost of fugitive emission during fuel extraction, processing and transport effectively adds to the cost of fuel to electricity generators. Because of fugitive emissions during transport and gas processing, the increase in gas price is relatively higher than for coal. Brown coal currently does not face a fugitive emissions impost. The average emission intensity of black coal generation also increases slightly due to fugitive emissions from around 0.9 t/MWh to 0.95 t /MWh
- Gaming is assumed right throughout this analysis. That is, generators are allowed to game up market prices in order to maximise their profit streams
- The brown coal generators in Victoria act as price setters (rather than price takers in the reference case) in the market. Older brown coal generators perform in a lower load duty. Because of relatively high gas prices, the potential for switching is limited at low to modest carbon prices. And as demand is flattened by emission trading, there is limited entry of new plant to compete with the older high emitting plant at low to modest carbon prices (less than \$50/t CO_2e). This enables these brown coal generators to set the price in the market and pass on the opportunity cost of purchasing permits.

Eventually, permit prices reach a point where it is no longer profitable to operate the older coal fired plant and the relative increase in electricity prices subdues as more low emitting plant enter the market.

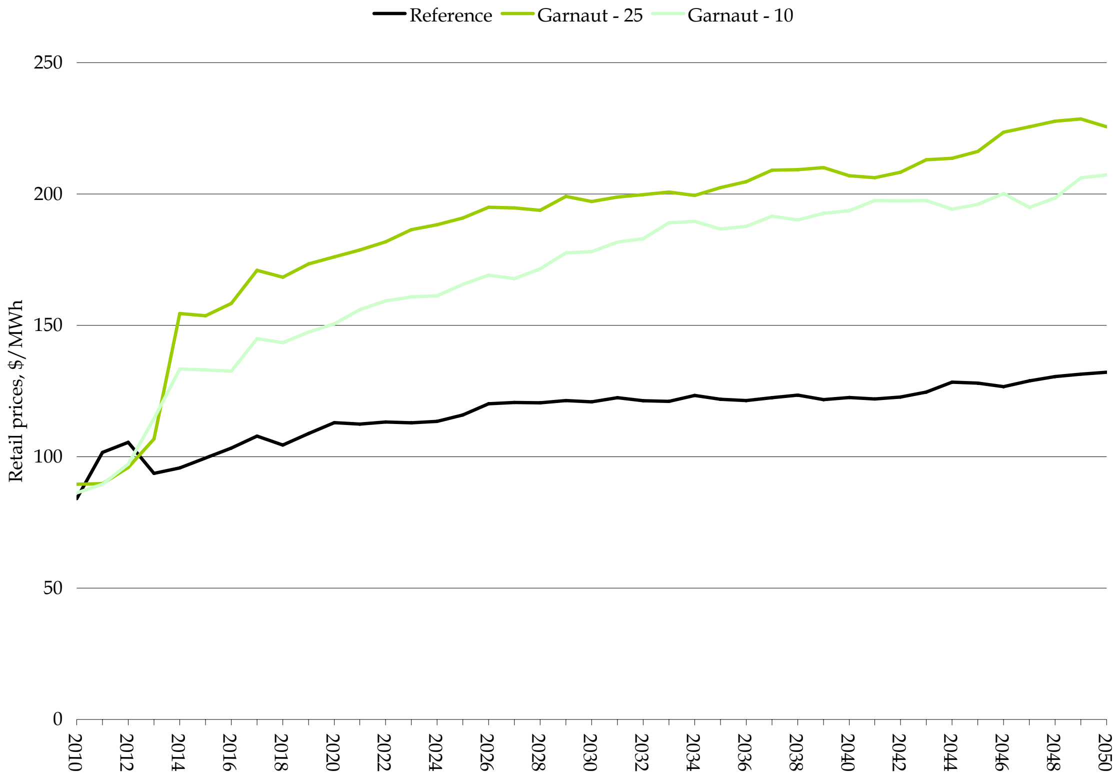
4.1.3 Retail prices

Retail prices comprise the wholesale price (multiplied by the marginal loss factor in transmission) plus network fees plus gross retail margins, market fees and the cost of administering various government schemes such as MRET and the CPRS.

Retail price increases observe the same patterns as for wholesale prices (see Figure 4-4 and Table 4-2). The percentage increase rises steadily from 25% for the smallest cut in emissions to 40% for the deepest cut in the period to 2020. After 2020, retail prices are expected to increase on average by about 60% for the Garnaut -10% scenario, 80% for the Garnaut -25% scenario and around 55% for other scenarios.

In terms of household expenditure on electricity in the period to 2020, the retail price increase translates into additional expenditure on electricity ranging from \$0.20 per week (Western Australia) to \$1.20 per week (NSW) for the Garnaut -10% scenario; from \$0.50 per week (Western Australia) to \$1.50 per week (Tasmania) for the Garnaut -25 scenario, and from \$0.70 per week (Western Australia) to \$1.75 per week (NSW) in all other scenarios. In the period after 2020, the retail price increases translates into additional expenditure of between \$4.30 per week to \$8.40 per week for the Garnaut -10 scenario, between \$4.40 per week to \$10.20 per week for the Garnaut -25 scenario, and between \$4.10 per week to \$10.10 per week for all other scenarios.

Figure 4-4: Australian Retail prices, $/MWh



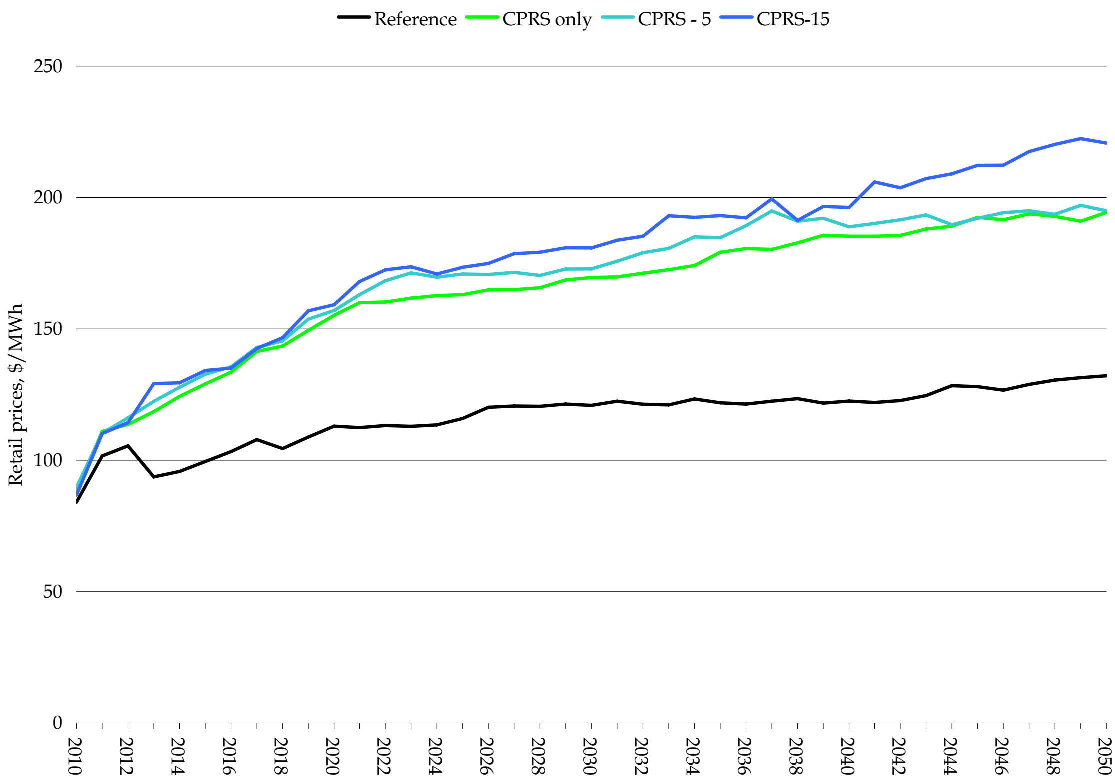


Table 4-2: Retail price changes relative to Reference case

	Garnaut -25			Garnaut -10			CPRS Only			CPRS -5			CPRS -15		
	2010-2020	2021-2030	2031-2050	2010-2020	2021-2030	2031-2050	2010-2020	2021-2030	2031-2050	2010-2020	2021-2030	2031-2050	2010-2020	2021-2030	2031-2050
Change from Reference, $/MWh															
Queensland	42	67	86	24	44	76	25	43	62	28	49	70	29	53	77
New South Wales	40	78	93	26	50	74	28	48	62	32	56	66	34	61	83
Victoria	45	98	106	26	68	74	29	65	73	33	71	76	34	80	94
Tasmania	37	80	75	18	56	53	24	55	50	25	58	53	27	69	70
South Australia	39	71	69	28	59	60	28	45	34	29	49	45	29	56	68
Western Australia	23	55	77	12	32	56	24	28	53	19	33	58	15	23	51
Northern Territory	16	48	86	5	22	39	13	20	31	12	19	30	16	26	42
% Change from Reference															
Queensland	44	59	74	26	38	66	26	38	54	30	43	61	31	46	67
New South Wales	40	69	77	26	44	61	28	43	51	32	50	54	34	55	68
Victoria	44	88	87	25	61	61	28	59	60	33	64	62	34	72	77
Tasmania	36	71	59	18	50	41	23	49	39	24	51	42	26	61	55
South Australia	36	57	49	25	47	42	26	36	24	27	40	32	27	45	48
Western Australia	19	40	54	9	23	39	19	21	38	15	24	41	12	17	36
Northern Territory	8	24	42	3	11	19	7	10	15	6	9	15	9	13	21

Table 4-3: Additional expenditure on electricity by households, $/week

	Garnaut -10					Garnaut -25					CPRS Only					CPRS -5				
	2010-2020	2021-2030	2031-2040	2040-2050	2010-2050	2010-2020	2021-2030	2031-2040	2040-2050	2010-2050	2010-2020	2021-2030	2031-2040	2040-2050	2010-2050	2010-2020	2021-2030	2031-2040	2040-2050	2010-2050
Queensland	1.30	6.66	6.97	8.78	5.82	1.00	4.45	6.12	8.73	4.98	1.13	4.48	4.70	7.15	4.29	1.38	5.13	5.97	8.71	5.20
NSW	1.39	6.75	7.64	8.71	6.01	1.19	4.73	6.03	7.67	4.81	1.35	4.78	4.70	6.39	4.23	1.65	5.58	5.78	7.25	4.98
Victoria	1.18	6.34	7.78	7.93	5.69	0.92	4.44	6.60	6.21	4.45	1.08	4.51	5.88	6.41	4.39	1.30	5.24	6.56	6.84	4.90
Tasmania	1.47	8.96	10.23	9.02	7.27	0.92	6.00	8.41	6.77	5.42	1.34	6.37	7.39	6.30	5.25	1.43	7.03	8.05	7.06	5.78
South Australia	1.22	5.25	5.75	5.70	4.40	1.17	4.31	5.91	5.06	4.04	1.25	3.75	3.22	2.75	2.71	1.37	4.16	4.29	4.06	3.42
Western Australia	0.49	4.41	5.36	7.29	4.29	0.20	2.61	3.85	5.88	3.06	2.84	2.39	3.24	5.39	3.45	0.79	2.83	4.14	6.18	3.42
Northern Territory	1.42	7.47	5.09	8.00	5.50	1.20	3.47	3.66	6.08	3.60	1.97	3.15	3.07	4.80	3.25	1.62	2.63	3.93	4.20	3.10

Note: The impact on higher electricity prices on reducing electricity demand has been included in this analysis.

4.2 National Generation Mix

Under emission trading coal fired generation is predicted to remain steady or decline slightly over time under the emission trading scenarios modelled. Both black and brown coal fired generation falls relative to levels predicted with no emission trading. Most of the reduction occurs in Victoria, Queensland and New South Wales. Coal-fired generation is limited in other states.

Figure 4-5: Generation trends for the reference scenario (no emission trading)

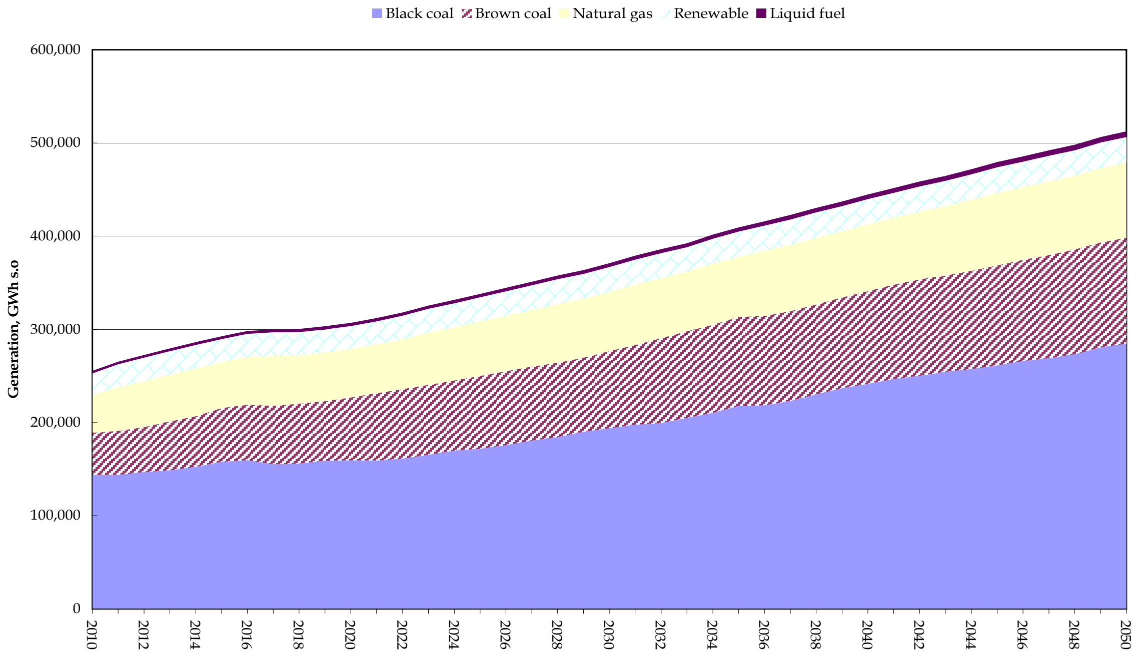


Figure 4-6: Generation trends for the CPRS only scenario

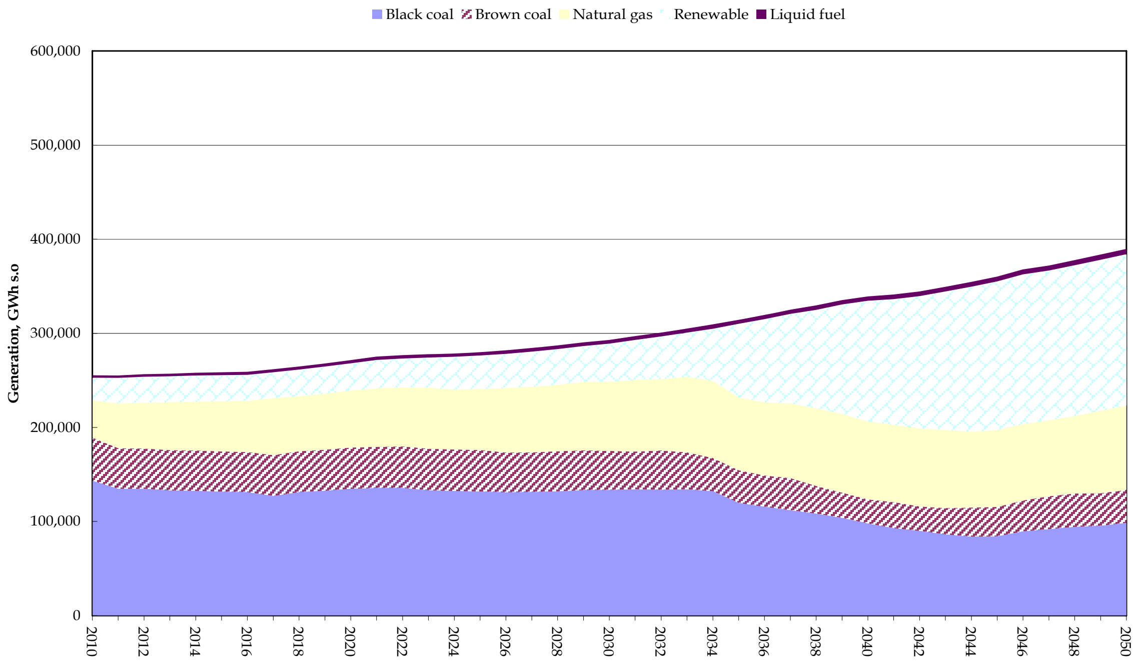
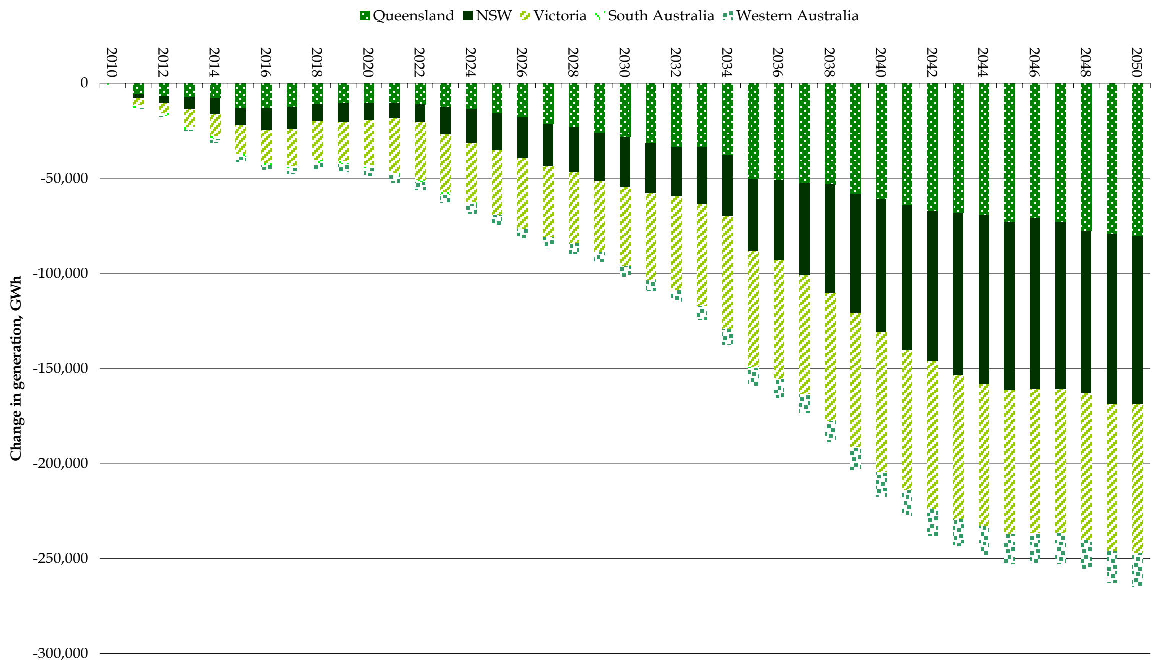


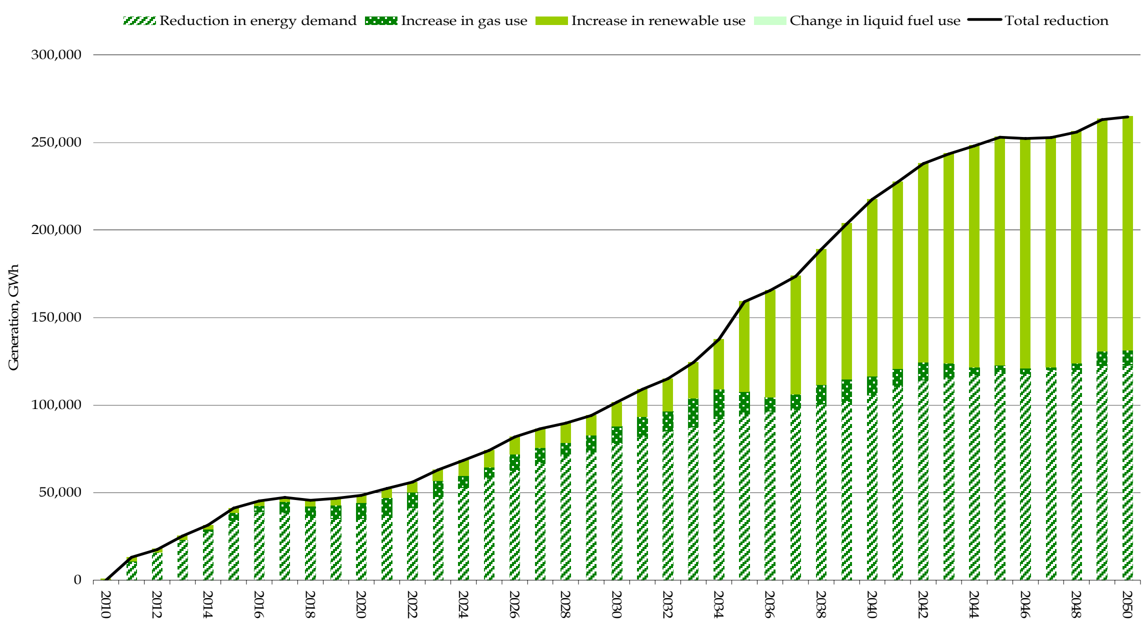
Figure 4-7: Reduction in coal generation by state, CPRS only scenario



Three factors contribute to the decrease in coal fired generation:

- The reduction in electricity demand, which is the major contributor in the short-term and contributes nearly half of the reduction over the longer-term.
- Fuel switching to gas-fired generation, although this factor contributes only a small proportion of the reduction.
- Entry of new renewable generation, which contributes over half of the decrease in the long-term.

Figure 4-8: Factors affecting the reduction in coal generation, CRPS only scenario



The permit price at which fuel switching from coal to gas occurs is much higher than anticipated due to the higher gas prices. For the short-term period, it is still economically viable for the coal plants to generate, as they are still setting the price for a large proportion of the time, and thus are able to pass through emissions trading costs onto the electricity price.

Without the development of carbon capture and storage technologies, coal fired generation could be even lower than predicted. Capture and storage technology was assumed not to be available until 2020 and, aside from renewable generation, dominates the landscape of new entrants after 2030. The emissions captured and stored by these units for each region were input into MMA's model of carbon sequestration to ensure that there were no capacity constraints on the volume of CO_2 to be stored.

Figure 4-9: Cumulative CO_2 emissions captured for storage

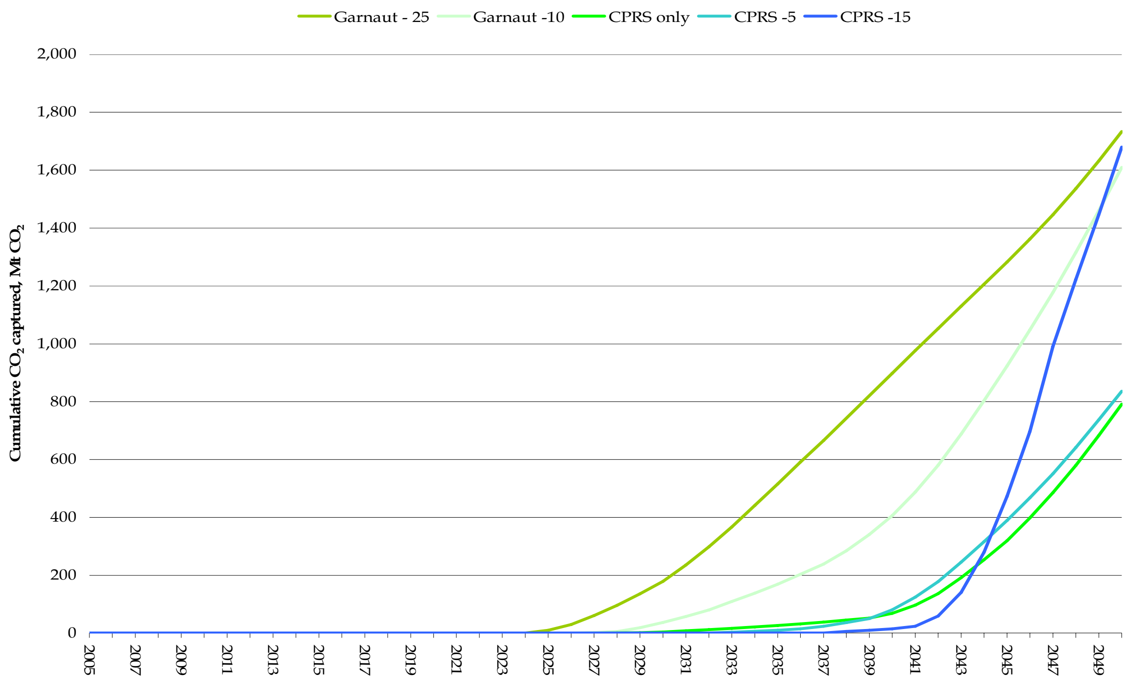


Table 4-4: Cumulative emissions captured for storage by State, 2050

	Garnaut -10	Garnaut -25	CPRS only	CPRS -5	CPRS -15
Queensland	576	815	237	301	437
New South Wales	290	261	232	252	903
Victoria	605	384	206	200	270
Tasmania	0	0	0	0	0
South Australia	8	5	4	0	0
Western Australia	130	269	112	83	70
Northern Territory	0	0	0	0	0
Total	1,610	1,733	791	836	1,680

APPENDIX A DETAILED ASSUMPTIONS USED IN THE ELECTRICITY MARKET MODEL

A.1 Introduction

The market simulations take into account the following parameters:

- Regional and temporal demand forecasts
- Generating plant performance
- Timing of new generation including embedded generation
- Existing interconnection limits
- Potential for interconnection development

The following sections summarise the major market assumptions and methods utilised in the forecasts.

A.2 Software Platform

The wholesale market price forecasts are developed utilising MMA's National Electricity Market model. This model is based on the Strategist probabilistic market modelling software, licensed from New Energy Associates. Strategist represents the major thermal, hydro and pumped storage resources as well as the interconnections between the NEM regions. In addition, MMA partitions Queensland into four zones to better model the impact of transmission constraints and marginal losses. These constraints and marginal losses are projected into the future based on past trends.

The simplifications in bidding structures and the way Strategist represents inter-regional trading, result in slight under-estimation of the expected prices because:

- All the dynamics of bid gaming over the possible range of peak load variation and supply conditions are not fully represented
- Extreme peak demands and the associated gaming opportunities are not fully weighted. These uncertainties are highly skewed and provide the potential for very high prices outcomes with quite low probability under unusual demand and network conditions
- 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.

However, overall corrections can be made where these measures are important and in any case the error in modelling is comparable to the uncertainty arising from other variable market factors such as contract position and medium term bidding strategies of portfolios.

Overall the results presented in this report represent a conservative view, applicable for long-term investment in generation capacity.

A.3 Methodology

Average hourly pool prices are determined within Strategist based on thermal plant bids derived from marginal costs or entered directly. The internal Strategist methodology is represented in Figure A-1 and the MMA modelling procedures for determining timing of generation and transmission, and bid factors are presented in Figure A-2.

Figure A-1: Strategist Analysis Flowchart

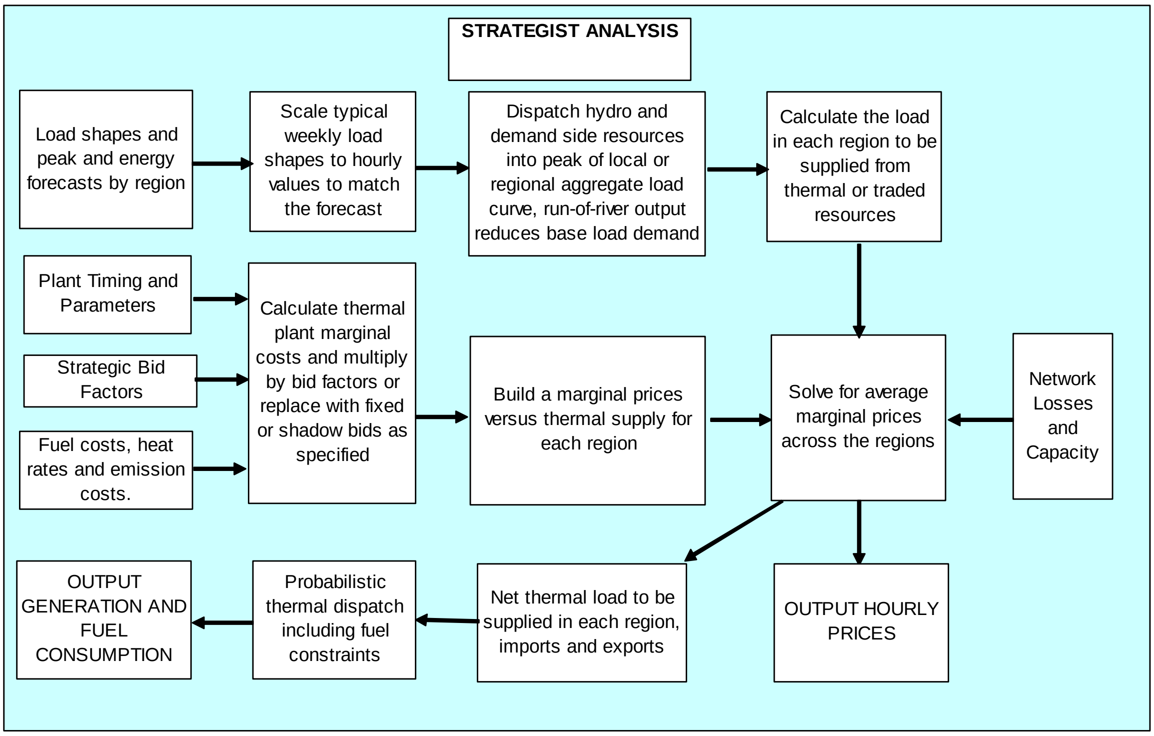
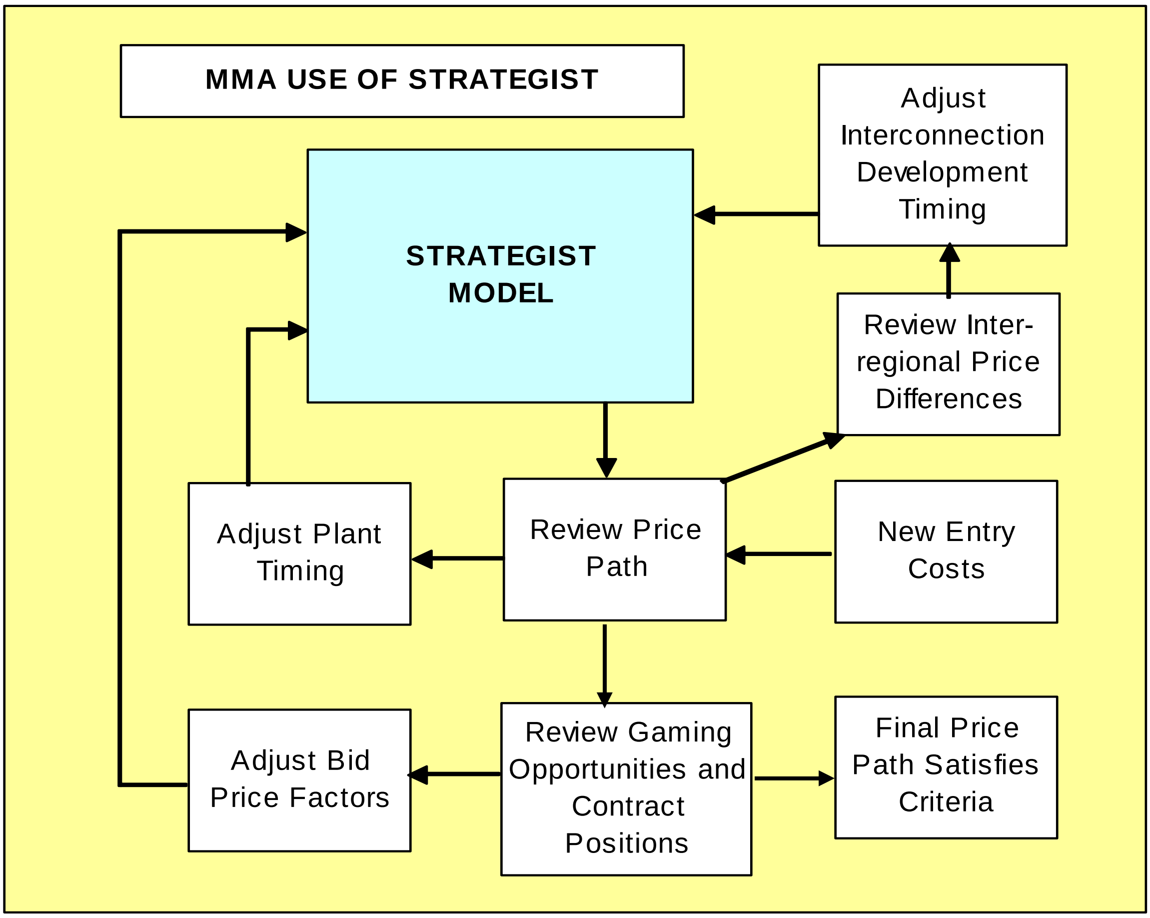


Figure A-2: MMA Strategist Modelling Procedures



Strategist generates average hourly marginal prices for each hour of a typical week for each month of the year at each of the regional reference nodes, having regard to all possible thermal plant failure states and their probabilities. The prices are solved across the regions of the NEM having regard to inter-regional loss functions and capacity constraints. Failure of transmission links is not represented although capacity reductions are included based on historical chronological patterns. Constraints can be varied hourly if required and such a method is used to represent variations in the capacity of the Heywood interconnection, between Victoria and South Australia, which have been observed in the past when it was heavily loaded.

Bids are generally formulated as multiples of marginal cost and are varied above unity to represent the impact of contract positions and the price support provided by dominant market participants. Some cogeneration plants are bid below unity to represent the value of the steam supply which is not included in the power plant model.

The Strategist model can handle regions with high levels of hydro-electric generation (Snowy Region and Tasmania). The value of hydro electric generation in these regions are set to the opportunity cost of the thermal generation in the regions in which the generation is exported, the opportunity cost of imported power or the short run marginal cost of thermal generation in that region.

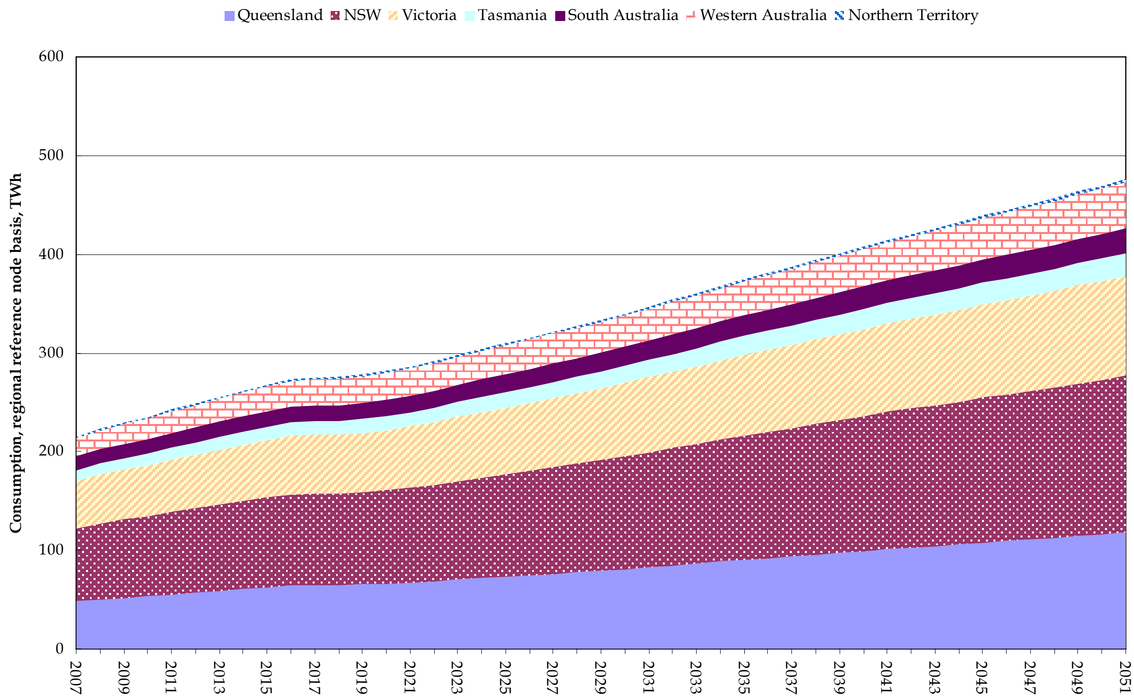
A.4 Demand assumptions

Demand projections are derived from the MMRF computable general equilibrium model of the Australian economy. Details of the assumption underpinning the economic conditions in the reference scenario are outlined in a separate report. These demand forecasts differ from those provided by market operators (such as NEMMCO) and transmission system planners due to differing assumptions regarding economic growth, demographic factors and other factors affecting electricity demand. Treasury demand projections were used to ensure consistency of results across the bottom up and top down modelling.

A.4.1 Energy consumption

Projections of energy consumption by State are shown in Figure A-3 for the Reference case. Energy consumption is projected to continue on growing, increasing from 215 TWh in 2006/07 to 282 TWh in 2019/20 to 340 TWh in 2029/30 and to 470 TWh in 2049/50. Growth is relatively flat over the next decade, averaging around 2.18% per annum in the period to 2017/18. Thereafter, growth is expected to average around 1.7% per annum.

Figure A-3: Energy consumption projections



A breakdown by state of energy consumption is shown in Table A-1. Queensland and Western Australia are projected to have the highest growth rates. Victoria, Tasmania and South Australia are expected to have the lowest growth rates.

A comparison was made between the projections from the MMRF model and alternative published projections, adjusted to include loads from embedded generation but eliminate loads from remote area power supplies and minor grids (see Table A-2). Published projections are sourced from the operators responsible for operating the grids in each State

(NEMMCO, WA IMO and NT Utilities Commission)[11]. The projections from MMRF are within +/- 7% of the published projections for 2009/10 and +11% to -9% for 2019/20. The biggest differences occur in Western Australia and Northern Territory, where the MMRF projections are higher and Tasmania, where the MMRF projections are lower.

Table A-1: Energy consumption in the major grids by state

	2005/06	2009/10	2019/20	2029/30	2049/50
Consumption, TWh					
Queensland	49	53	66	81	116
New South Wales	74	81	95	114	157
Victoria	48	52	61	74	100
Tasmania	11	11	14	17	23
South Australia	14	15	17	20	25
Western Australia	18	21	27	31	46
Northern Territory	1	2	2	2	3
Growth rate, % per annum					
Queensland	3.0%	2.2%	2.0%	1.9%	3.0%
New South Wales	3.1%	1.6%	1.9%	1.7%	3.1%
Victoria	2.5%	1.7%	2.0%	1.7%	2.5%
Tasmania	1.7%	2.1%	2.0%	1.6%	1.7%
South Australia	2.5%	1.2%	1.6%	1.3%	2.5%
Western Australia	4.7%	2.7%	1.4%	1.8%	4.7%
Northern Territory	4.7%	2.3%	1.2%	1.5%	4.7%

Note: Covers demand for loads connected to the NEM for the eastern states, Tasmania and South Australia. Covers demand for loads connected to the SWIS in Western Australia and connected to the DKIS in the Northern Territory.

11 The published sources usually only provided projections out to 2015/16. Projections from published sources for the 2019/20 year are derived by extrapolating out from the published projections.

Table A-2: Comparison of energy consumption projections

	2009/10			2019/20		
	MMRF	Published	% difference	MMRF	Published	% difference
Queensland	53	53	1.4%	66	72	-7.9%
New South Wales	81	79	3.2%	95	93	1.7%
Victoria	52	50	2.2%	61	60	0.7%
Tasmania	11	12	-2.1%	14	13	4.6%
South Australia	15	14	4.3%	17	16	4.1%
Western Australia	21	21	0.8%	27	25	9.4%
Northern Territory	2	2	2.2%	2	2	-4.8%

Note: Published projections for NEM states sourced from NEMMCO statement of opportunities and are derived by including embedded generation demand included in the NEMMCO document. Published projections for the SWIS in Western Australia come from the WA Independent Market Operator. Published projections for the DKIS in Northern Territory come from the NT Utilities Commission.

A.5 Peak demand – summer

Peak demand projections are derived from the MMRF energy consumption projections. The basis is to preserve the trends in peak demand observed in the published forecasts.

The process for deriving summer peak demand projections is as follows:

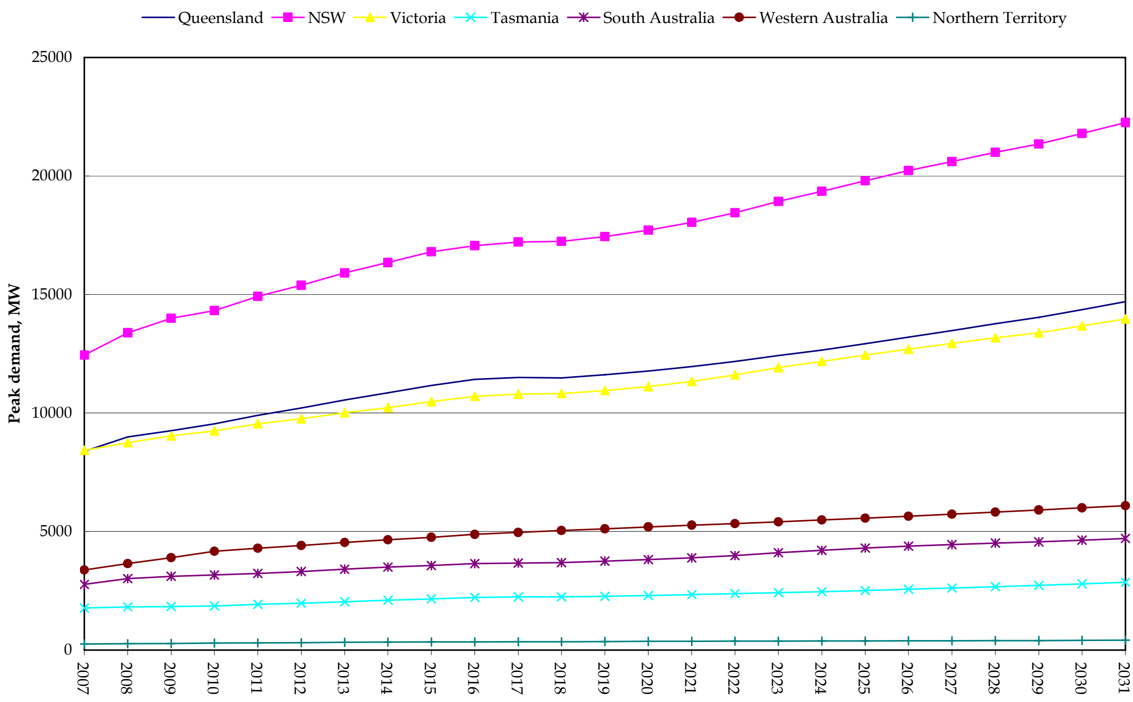
- Use MMRF energy consumption projections
- Derive load factors for each year of the projection period by taking forecasts of energy consumption and peak summer demand from published sources. That is, load factors for the NEM states are derived from the energy consumption and peak demand projections for each state published by NEMMCO
- The load factors for each year are derived by the following formula:

  Load Factor = (Energy consumption/8.76)(1/Peak demand)*

  Where load factor is a percent, energy consumption is in GWh and peak demand is in MW
- Peak demand is then derived by multiplying the load for each state by MMRF' energy consumption projection for that State.

The derived projections for peak demand are shown in Figure A-4. Compound growth rates in peak demand from 2005/06 to 2029/30 are: Queensland –3.3% per annum; New South Wales -2.3% per annum; Victoria –2.2% per annum; Tasmania - 1.2% per annum; South Australia –1.7% per annum; Western Australia – 3.0% per annum; and Northern Territory –3.5% per annum.

Figure A-4: Peak demand projections



A.6 Supply assumptions for the NEM

The business as usual case reflects the most probable prices given the current state of knowledge of the market. Common features of the business as usual case and other scenarios include:

- The Queensland Gas Electricity Scheme continues until 2020 in the business as usual scenario. The target increases from 13% in 2006 to 15% in 2010 and then linearly to 18% in 2020. The target remains at 18% until 2030. In the emissions trading scenario, the policy is assumed to stop at the commencement of emissions trading (2009/10 year).

- In the business as usual scenario, the NSW Greenhouse Gas Abatement Scheme is assumed to cease operation in 2012. This is to allow proper calculation of the economic costs of introducing emissions trading without the results being confounded by the impacts of other large scale abatement schemes. In the emissions trading scenarios the NGGAS scheme was assumed to cease at the start of 2010/11.

- PNG/Timor Sea gas supply delivered to Queensland for new power generation and for supply to southern and eastern seaboard markets from July 2022.

- Generators behaving rationally, with uneconomic capacity withdrawn from the market and bidding strategies limited by the cost of new entry.

- Infrequently used peaking resources are bid near VoLL.

- Until new plant are required, the generator bidding profiles reflect generator contracting levels and assumed revenue targets, based on MMA's benchmark study for 2004 calendar year. From the time new plant are required, all generators except infrequently used peaking plant bid in at short run marginal cost.
- Moomba to Sydney gas pipeline tariffs are consistent with the July 2002 submission to the ACCC by the Australian Pipeline Trust.
- The commissioning of Kogan Creek as a base load generator in Queensland at the beginning of September 2007.
- The retirement of Swanbank B units in 2011.
- Condamine and Darling Down Power gas-fired power stations in Queensland are assumed to proceed as planned.
- Munmorah and Urquantary Power Stations (based on gas-fired open cycle gas turbines) proceed as planned.
- A 170 MW VIC->SA upgrade on the Heywood interconnector in July 2009 to augment supply to South Australia.
- A series of network augmentations as required (see Section A.4.8 below).

A.6.1 Market structure

We assume the current market structure continues under the following arrangements:

- Existing government owned NSW generators remain under the current structure in public ownership.
- Existing government owned Queensland generators remain in public ownership.
- Existing government owned generators in Tasmania remain in public ownership.
- The South Australian and Victorian generators continue under existing portfolio groupings.

A.6.2 Marginal costs

The marginal costs of thermal generators consist of the variable costs of fuel supply including fuel transport plus the variable component of operations and maintenance costs. The indicative variable costs for various thermal plants are shown in Table A-1. For coal plant, the marginal cost of fuel is based on the opportunity cost of the fuel. In the case of power stations supplied from mines not owned by them, the opportunity cost reflects forecasts of the export parity price of coal (as published each year by ABARE). We also include in the marginal fuel costs for brown coal the net present value of changes in future capital expenditure that would be driven by fuel consumption for open cut mines that are owned by the generator. This applies to coal in Victoria and South Australia.

Table A-3: Indicative Average Variable Costs for Thermal Plant

Technology	Variable Cost $/MWh	Technology	Variable Cost $/MWh
Brown Coal – Victoria	$6 - $11	Brown Coal – South Australia	$18 - $24
Gas – Victoria	$38 - $57	Black Coal – New South Wales	$18 - $21
Gas – South Australia	$32 - $96	Black Coal - Queensland	$13 - $21
Oil – South Australia	$186 - $233	Gas - Queensland	$22 - $60
Gas Peak – South Australia	$85 - $122	Oil – Queensland	$212

Our estimates of marginal cost are higher than those estimated by ACiL Tasman in a report for NEMMCO. The difference between MMA numbers and ACiL Tasman numbers depend on what your view is of fuel costs: contract fuel prices can be considered a fixed cost (in which case the marginal cost is very low) or as an opportunity cost if there is an alternative market for the fuel (such as a spot market for gas). We consider the latter approach to be more appropriate for most power stations except for existing mine mouth coal stations. We have always taken comfort of our SRMC estimates based on the close alignment of our model and actual bids and pool prices in off peak periods, when gaming is likely to be less prevalent. With gaming, the outcome is not likely to be greatly different from our current results.

A.6.3 Plant Performance and Production Costs

Thermal power plants are modelled with planned and forced outages with overall availability consistent with indications of current performance. Coal plants have available capacity factors between 86% and 95% and gas fired plants have available capacity factors between 87% and 95%

Emissions factors for each plant are modelled on a fuel basis (that is, kt CO_2e/PJ fuel consumed). The emissions factors for each generating unit are equal to the factors assumed in the latest edition of the National Greenhouse Gas Inventory as published by the DCC.

A.6.4 Timing of new entry

After selecting new entry to meet NEMMCO's minimum reserve criteria, MMA's pool market solution may indicate when prices would support additional new entry under typical market conditions and these are included in the market expansion if required. Interconnections

Assumptions on interconnect limits are based on the maximum recorded inter-regional capabilities for 2004/05. The actual limit in a given period can be much less than these maximum limits, depending on the load in the relevant region and the operating state of generators at the time. For example, in the case of the transfer limit from NSW to Queensland via QNI and Directlink, the capability depends on the Liddell to Armidale network, the demand in Northern NSW, the output from Millmerran, Kogan Creek and

Braemar, and the limit to flow into Tarong. Over time we expect that the constraints for power flow into Queensland would be relieved so that new generating capacity in the south-west can support the Brisbane area. These constraints are formulated in a simplified way in the Strategist model.

There are a number of possible interconnection developments being considered including:

- An upgrade of the existing Victoria to South Australia export limit from 460 MW to 630 MW by additional transformation at Heywood Terminal Station and possibly series compensation on the Tailem Bend - South East 275 kV lines
- Network augmentation through series compensation in South East Queensland.
- 100 MW increase in line rating on QNI in both directions through thermal rating upgrade of the Armidale – Tamworth 330 kV line
- Relaxation of some constraints affecting southerly flow on QNI by installing a phase angle regulator to prevent overloading on the Armidale – Kempsey 132 kV line
- A 180 MW upgrade of the Snowy to Victoria transmission link over time which would enable additional imports from Snowy/NSW into Victoria. This option has been further developed to include an augmentation of 180 MW and then up to 2500 MW total transfer from Snowy to Victoria.

Table A-4: Interconnection limits – based on maximum recorded limits

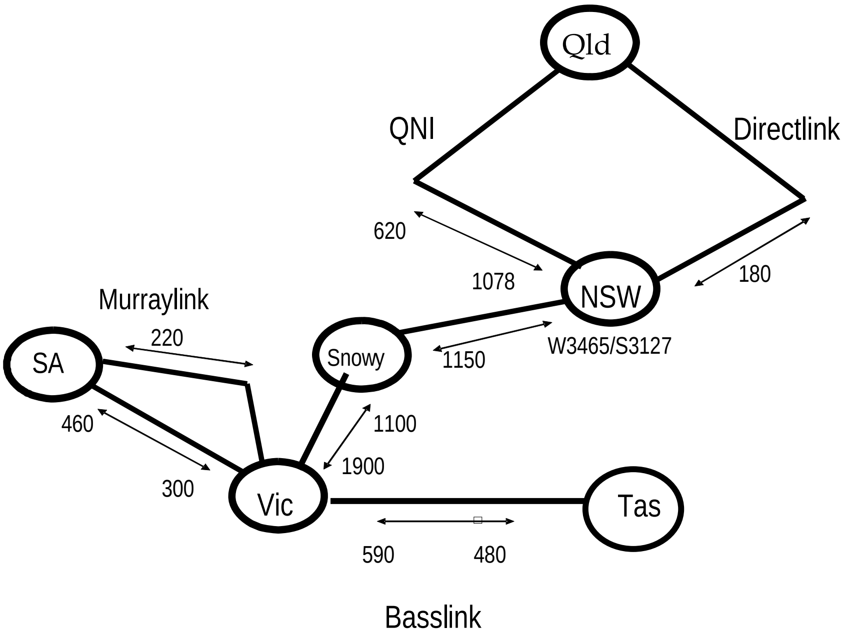
From	To	Date	Summer Capacity
Victoria	Tasmania		480 MW
Tasmania[1]	Victoria		590 MW
Victoria	South Australia		460 MW
Victoria	South Australia	Jul-09	630 MW
South Australia	Victoria		300 MW
South Australia	Redcliffs		135 MW
Redcliffs	South Australia		220 MW
Victoria	Snowy		1100 MW
Snowy	Victoria		1900 MW
Snowy	New South Wales		3127 MW
New South Wales	Snowy		1150 MW
New South Wales	South Queensland		180 MW
South Queensland	New South Wales		195 MW
New South Wales	Tarong (QNI)		621 MW
Tarong	New South Wales (QNI)		1078 MW

Source: [1]Assumed to only occur for a maximum continuous period of 6 hours.

In modelling the NEM, we augment the existing interconnections according to these conceptual augmentations as required. Further upgrades to relax the Tarong limit are assumed to proceed as required to ensure that capacity in the Tarong region can reach the South East Queensland load.

MMA's pool market solution indicates when prices would support new entry under typical market conditions and these are included in the market expansion accordingly. We use cost data for potential interconnect upgrades as provided in the SOO published by NEMMCO. The model selects those expansions that are lower cost than increasing generation within constrained regions.

Figure A-5: Representation of interconnections and their limits in Strategist



A.6.5 Transmission losses

Inter-regional loss equations are modelled in Strategist by directly entering the Loss Factor equations published by NEMMCO except that Strategist does not allow for loss factors to vary with loads. Therefore we allow a typical area load level to set an appropriate average value for the adjusted constant term in the loss equation. The losses currently applied are those published by NEMMCO.

Negative losses are avoided by shifting the quadratic loss equation so that the minimum passes through zero loss.

Intra-regional losses are applied as published by NEMMCO. The long-term trend of marginal loss factors is extrapolated for two more years and then held at that extrapolated value thereafter.

A.6.6 Hydro Modelling

Hydro plants are set up in Strategist with fixed monthly generation volumes. Strategist dispatches the available energy to take the top off the load curve within the available capacity and energy. Any run-of-river component is treated as a base load subtraction from the load profile.

These monthly energy limits provided by NEMMCO in the 2005 ANTS have been validated by comparison against historical hydro sequences that are derived from published generation data found at www.erisk.net. Erisk is a live source of combined news, prices, data and analyses for the Australian Energy Market. Where the hydro sequences appear ill-aligned to the NEMMCO energy limits, the average monthly generation levels are used in place of the NEMMCO limits to represent an estimate of the long-run monthly energy limits. Table A-6 shows the monthly energies used in our Strategist model. Table A-7 shows the annual energy for the Snowy Scheme.

Table A-5: Maximum monthly energy availability for small hydro generators modelled in Strategist (GWh)

Month	Barron	Hume NSW	Hume VIC	Kareeya	Dartmouth	Eildon 1-2	Kiewa, McKay
January	13.96	4.19	18.75	23.32	24.98	19.13	10.01
February	20.56	3.44	15.19	22.91	26.37	14.71	10.6
March	22.63	0.22	14.53	23.60	11.87	15.51	5.98
April	15.47	0.21	6.53	20.42	3.48	7.49	4.33
May	11.28	0.00	0.62	25.02	4.71	1.37	11.44
June	9.40	0.00	0.09	25.80	9.58	0.32	19.4
July	10.07	0.94	0.01	32.05	36.78	0.88	28.89
August	7.93	4.47	1.09	30.18	34.77	3.3	23.06
September	8.51	7.86	6.97	22.61	31.76	4.98	30.8
October	12.02	6.71	14.61	23.34	33.33	7.4	43.71
November	13.38	3.47	20.25	21.30	35.99	8.98	23.03
December	10.52	5.91	20.66	28.05	31.14	17.6	15.93

Table A-6: Annual Energy Limits from Snowy Hydro

	Blowering	Guthega	Murray	Upper Tumut	Lower Tumut
Annual Limit (GWh)	240	250	2,210	1,630	745

Based on our market information we have produced detailed information on monthly and annual maximum and minimum energy limits for the Snowy Hydro units. This information has been incorporated into the Strategist simulation as monthly energy generation.

Murray 1 releases will be progressively reduced with increasing environmental releases, particularly down the Snowy River. Snowy Hydro estimates a reduction of 540 GWh/year after the 10 year programme is completed. Consequently, by July 2012 the Murray annual energy limit has reduced to 1738 GWh per annum. However, the model allows for additional generation from Murray after its modification is complete. Additional generation is also possible from the Tumut unit if the model selects the proposed upgrade of these units.

Hydro Tasmania is represented by a single equivalent hydro power station in the Strategist model with an average annual yield of 10,133 GWh. Modelling Hydro Tasmania as one equivalent station has no implications for the modelling of impacts of emissions trading. However, recent low inflow data may reflect a permanent reduction in annual inflows due to the impact of climate change on rainfall. This may need to be considered in further analysis.

Table A-7: Monthly energy inflows for Tasmanian hydro (GWh)

Month	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Year
Long-term	77	66	86	197	288	330	399	417	366	292	192	141	2,851
Mid-term	147	120	145	325	462	495	601	595	530	435	313	230	4,398
Run of river	131	110	125	206	275	311	364	364	320	280	221	177	2,884
Total	355	296	356	728	1,025	1,136	1,364	1,376	1,216	1,007	726	548	10,133

Source: ANTS 2005.

The average annual yield from all 3 storages is assumed to have increased with the commissioning of Basslink. The monthly limits have been pro-rated each year in line with this annual yield which appears in the above table. The latest report from Hydro Tasmania indicated that it will return only to 9,500 GWh and so this has been assumed. However, a 10% upgrade potential is also modelled as part of the renewable energy mix.

A.7 SWIS Assumptions

The South West Interconnected System (SWIS) covers the electricity grid in the south-west corner of Western Australia, from Geraldton in the north to Kalgoorlie in the east. It covers the major load centres of Perth, Kwinana Industrial Zone, Fremantle and Kalgoorlie. Verve Energy is the dominant generator, competing largely against some smaller independent power producers and surplus from independent cogeneration plant.

In this section, we present the key assumptions underpinning MMA's market model of the SWIS.

A.7.1 Trading arrangements

The wholesale market for electricity in the SWIS has been restructured into:

- An energy trading market, which is an extension of the existing bilateral contract arrangements
- An ancillary services market to trade spinning reserve and other services to ensure supply reliability and quality.

The SWIS is relatively small, and a large proportion of the electricity demand is from mining and industrial use, which is supplied under long-term contracts. The basic principle of the market design is for a bilateral contracts market to continue to underpin the SWIS, with a residual day ahead trading market (called the STEM). This residual trading market is anticipated to allow contract participants to trade out any imbalances, and also allow small generators to compete where they would otherwise not be able to, due to their inability to secure contracts.

Market participants will have the option of either entering into bilateral contracts or trading in the STEM.

The ancillary services market is the responsibility of system management. System management will be required to determine the least cost supplies to satisfy the system security requirements. Both independent generators and state generation could be ancillary reserve providers, but at least initially it is envisioned that the state generator will need to provide all spinning reserve under contract with system management.

All market participants will need to pay for the ancillary services. In our SWIS model, we assume that there is a market for trading spinning reserve. Providers receive revenue for this service, and the cost is allocated to all generators above 115 MW with the largest cost disproportionately allocated to the largest unit.

A.7.2 Market rules

Under the market rules applying to the operation of the STEM:

- All generation plants will be self-scheduled to meet their bilateral and STEM contract positions, which mean that they determine when to be committed and de-committed
- Bilateral contracts will be self-dispatched, however system management may over-ride this dispatch to maintain system security
- Supply and demand will be balanced in the STEM by centrally determining the residual dispatch requirements
- A single market-clearing price will exist in the STEM. This price will exclude the effect of network congestion
- Maximum prices in the STEM will be capped at the SRMC of gas and distillate peaking plant.

In the MMA model of the SWIS, we ignore bilateral contracts and allow all generation to be traded in the market. Our reasoning behind this is that the contract quantities and prices will be very similar to the market dispatch – otherwise one or other party would not be willing to enter the contract. Admittedly, contracts provide benefits from hedging that will not be reflected in the trading market. However, in the long-run, the differences between contracts and the trading market will be minimal.

We have also assumed a $10,000 Value of Lost Load (VOLL) in line with the NEM, to ensure long-term supply reliability.

A.7.3 Structure of generation

In our model, we assume that Verve Energy is one generating entity. To encourage competition, Verve Energy will not be automatically allowed to build new plant to replace its old or inefficient plant. To allow Western Power to bid for new entry generation as long as its overall generation capacity does not exceed 3,000 MW.

A.7.4 Demand assumptions

Three key demand parameters are used in the model:

- Peak demand at busbar.
- Energy requirements.
- Load profiles.

We use MMRF's energy sent out forecasts for Western Australia to determine energy forecasts for the SWIS. We split these forecasts between regions, and added our projections of energy sent out at the Alcoa alumina refineries, to create MMA's projections for electricity sent out..

Projections of the summer and winter peak demand at generator busbar are derived from forecasts of sent out peak demand provided by the IMO. The same load factor as is implied by the IMO forecasts are used to derive peak demand forecasts from the energy sent out forecasts provided by MMRF.

Peak demand for each month is calculated based on the forecast summer peak demand and historical load profiles.

Using data provided by Western Power, MMA derived a SWIS load profile. This data was normalised to the peak value for the 2004/05 and then modified to ensure consistency with energy sales and load factors. The load growth algorithm in our simulation model then used this 'historical' load profile to forecast demand for the entire planning horizon, ensuring consistency with the annual peak and energy sales assumptions for the study period. This implies that we are assuming that the monthly pattern of energy sales and peak demand remains constant during the forecast period.

A.7.5 Fuel assumptions

In this report, all assumptions on fuel usage and unit costs are based on the higher heating value (or gross specific energy) for each fuel in line with accepted practices in Australia. Long-term levelised costs are estimated based on pre-tax costs and using a real discount rate of 9% pa.

Coal Prices

In the MMA model, coal prices after 2010 are assumed to be $45/t on a delivered basis for 19.3 GJ/t specific heat.

Gas prices

MMA assumes that new gas supply will be priced at $7.20/GJ in 2007 dollars with price escalating at 100% of the CPI increase and with international price trends. The transport charge is $1.10/GJ escalating at 75% of CPI.

All stations owned by Goldfields Power and Southern Cross Power are modelled to use Gold gas. The estimated well head price of this gas is $7.20/GJ. The gas transmission charge is assumed to be $3/GJ for gas supplied to the Goldfields region, reflecting the distances gas needs to be transmitted in this region, deflating at 75% of the CPI.

A.8 Darwin Katherine System

A.8.1 Contestability in the NT electricity system

The operation of the contestable market is based on:

- Bilateral trading – arranging supply directly with contracted (and contestable) end-use customers
- Supplying all of an individual contracted customers' demand under normal circumstances – partial contracting is not permitted
- Dispatching only the quantities demanded by their contracted customers as a group from the network, unless negotiation with other generators allows them to on sell their excess generation
- Contracting with other generators to provide and sell standby power whenever the independent generators' output is insufficient to meet their contracted supply (either because of breakdown or maintenance, or because their customers demand exceeds maximum output).

A.8.2 Model structure

The interconnected electricity grid in the Northern Territory is modelled as an integrated system with a transmission interconnection joining two regions: the Darwin Region and the Katherine Region. Loads include the major loads of Darwin and a number of mining site loads.

In formulating the model we assume that the bulk of electricity will be sold under bilateral contracts, with the balancing components dispatched according to economic merit order.

A.9 MMA renewable energy model

MMA has a detailed database of renewable energy projects covering existing, committed and proposed projects that supports our modelling of the REC price path. The database includes estimates of capital costs, likely reductions in capital costs over time, operating and fuel costs, connection costs, and other variable costs for individual projects that are operating, committed or planned[12].

For this assignment, the data base was updated and revised

Project costs have been obtained from published estimates of costs (usually capital costs) plus estimates of costs inferred from equipment suppliers, market data (for biomass fuel costs) and reports to Government. The costs are believed to be accurate to +/- 10% for existing and committed projects and +/- 20% for planned projects.

The MMA REMMA Model determines the future price path of RECs in the following steps:

- The costs of a range of renewable energy generation options have been determined as the levelised cost of generation using a 9.8%[13] real pre-tax weighted average cost of capital over at most a 20-year investment horizon. The model considers the time from the commencement of generation to the end of 2020 for REC revenue but only considers energy (electricity) revenue beyond 2020 earnt by the REC project if the 20 year investment horizon goes beyond 2020. The weighted average cost of capital estimate is also based on existing market rates for generation investments. Where data has been available the costs include the costs of connection to the grid, which can form a significant proportion of the capital costs of a project, particularly where no local transmission wires are available

- The spot market price or wholesale electricity cost in each of the regions of NEM has been used as the price that a generator could obtain for the power generated in the market. Wholesale electricity prices are determined on an hourly basis for each week of the study period, using Strategist model

- Assign regional wholesale electricity prices to all renewable projects in the data base according to location and start date. Weight wholesale electricity prices according to the generation profile of the renewable technology. For example, waste process generation would operate 24 hours per day and would therefore be represented by the average time-weighted pool price. Whereas, photovoltaic generation would only

12 Committed plant means projects that are either under construction or have achieved financial closure. Planned projects are those being actively investigated.

13 Based on debt to equity ratio of 75:25, real pre-tax interest on debt of 7.3% (9.0% in nominal terms) and real pre-tax return to equity of 17%. A premium of 1% applies to biomass projects to account for fuel supply risk.

operate through daylight hours, achieving the prevailing market price for these hours only. Solar hot water systems although using solar energy during daylight hours, actually replace off-peak electricity usage so the surrogate price for this option is the off-peak price for the replaced energy

- For each project, estimate any revenue from other sources such as fees for avoided landfill charges
- Potential revenues from wholesale market transactions and other sources for each project are levelised for the life of the project
- Subtract levelised revenue from corresponding renewable project levelised cost and then determine the merit order of the projects by ascending net costs (apart from those generators flagged as committed). The generation meeting the interim targets plus demand for banked credits in each year will determine which projects in the merit order will come on-line in a particular year
- The generation output from each project is calculated from the MW and capacity factor for each project
- The plant installed in each year is determined by the economic viability subject to the electricity price path under emissions trading
- The resulting MW installed and generation levels are then input into wholesale electricity market model to determine the resultant pool price changes that in turn impact the electricity prices under emissions trading
- The process may be repeated until stable outcomes result.

APPENDIX B ABATEMENT OPTIONS AND COSTS

B.1 Cost of new generation options

B.1.1 Renewable Energy

Unless otherwise stated, assumptions regarding the cost reduction opportunities have only been applied to the capital cost component of renewable projects, since this is the cost component that is most frequently discussed in the literature. This should be a reasonable simplification since capital costs typically constitute by far the largest component in the overall costs of renewable projects, unlike non-renewable generation projects.

Unless otherwise stated, the assumed rate of capital cost reduction for each technology is largely based on IEA predictions[14].

Hydroelectricity cost estimates are based on the values likely for small to medium sized developments (less than around 50 MW) in MMA's database. This is due to the fact that the vast bulk of Australia's hydro (large scale) potential has already been harnessed and any new projects are likely to involve the addition of capacity or refurbishment of existing large-scale developments, or the development of new mini-hydro plants.

As pointed out by the IEA, the hydropower industry is well established in many parts of the world and further opportunities for cost reductions are likely to be quite small compared with other renewable technologies. The exception is developing countries that display considerable potential for greater development. In particular, the potential for capital cost reductions from improved technology is likely to be limited, due to the advanced nature of existing turbine design.

Table B-1: Parameter values for hydroelectricity

Parameter	Units	Value	Change from 2005 to 2050
Size	MW	43.0	Unchanged
Life	Years	25	Unchanged
Real pretax WACC	%	9.0%	Unchanged
Capacity factor		0.30	Increase from 0.30 in 2005 to 0.35 in 2020 and remains constant
Interest during construction	%	7.0%	Unchanged
Fuel costs	$/MWh	0.0	Unchanged
O&M costs	$/MWh	0.0	Unchanged
Ancillary costs	$/MWh	0.0	Unchanged
Transmission costs	$/kW	100	Unchanged

14 International Energy Agency, 2003, *Renewables for Power Generation: Status & Prospects*, Paris, France.

The maximum additional potential mini-hydro plant is assumed to be around 100 MW, mainly in the eastern seaboard of Australia.

Generation costs for Australian wind farms are based on MMA's database of renewable energy projects in Australia. It is expected that improvements in wind turbine design and technology will lead to slight increases in capacity factor. However, it is possible that higher potential capacity factors resulting from technological improvements may eventually be offset by site limitations. As the level of installed wind capacity in Australia increases, it is likely that new wind farms may need to be located in areas with less than ideal wind regimes, thereby placing downward pressure on achievable capacity factors[15]. It has therefore been assumed that average capacity factors will increase linearly by 2 percentage points by 2020. However, from 2021 onwards, siting issues are expected to completely eliminate any further potential for increases in average capacity factors.

Table B-2: Parameter values for wind energy

Parameter	Units	Value	Change from 2005 to 2030
Size	MW	115.5	Unchanged
Life	Years	25	Unchanged
Real pretax WACC	%	9.0%	Unchanged
Capacity factor		0.33	Increase by 2% percentage points from 2005 to 2020 and does not increase further after this date
Interest during construction	%	7.0%	Unchanged
Fuel costs	$/MWh	0.0	Unchanged
O&M costs	$/MWh	5.0	Unchanged
Ancillary service costs	$/MWh	5.0	Unchanged
Transmission costs	$/kW	100	Unchanged

For biomass projects, cost estimates are primarily based on a recent report published by the Rural Industries Research and Development Corporation[16].

WACC is assumed to be slightly higher than some of the other renewables (1 percentage point higher) to account for biomass fuel supply risk. O&M costs are assumed to vary from $8.5/MWh to $15.5/MWh.

Given the difficulty in producing representative estimates of cost reductions for the large range of plant types that fall under the umbrella term of biomass, the capital cost reductions used in this study are based on the average IEA value.

15 AusWEA, 2004, *Cost Covergence of Wind Power and Conventional Generation in Australia*, Melbourne.

16 Stucley, C. R., Schuck, S. M., Sims, R.E.H, Larsen, P.L., Turvey, N.D. and Marino, B.E. 2004, *Biomass energy production in Australia: status, costs and opportunities for major technologies, A report for the Joint Venture Agroforestry Program (in conjunction with the Australian Greenhouse Office)*, ACT.

Biomass plants are the only renewable plants that are likely to experience significant fuel costs. Furthermore, the magnitude of fuel costs is likely to vary substantially for different types of biomass applications (for example, fuel costs in landfill gas applications could be expected to be close to zero, whereas for plants using purpose grown short cycle tree plantations, fuel costs are likely to be very high - potentially as high as $100/MWh or more[16]). The biomass costs in this analysis are based on the assumption that the biomass fuel is a by-product of another process (for example, bagasse from sugar cane harvesting), and the fuel cost is therefore low enough for biomass plants to be competitive with other renewable technologies such as wind.

Table B-3: Parameter values for bioenergy

Parameter	Units	Value	Change from 2005 to 2050
Size	MW	20.0	Unchanged
Life	Years	15	Unchanged
Real pretax WACC	%	10.0%	Unchanged
Annual capacity factor		0.80	Increase from 80% in 2005 to 85% in 2020 and remains constant.
Interest during construction	%	7.0%	Unchanged
Fuel costs	$/MWh	25.0	Unchanged
O&M costs	$/MWh	12.0	Unchanged
Ancillary service costs	$/MWh	0.0	Unchanged
Transmission costs	$/kW	100	Unchanged

For geothermal energy, the rate of decrease in capital costs is higher than all other renewable technologies (except solar PV). This seems reasonable, since geothermal technology is in its infancy in Australia and significant cost reduction opportunities are expected to occur as the installed capacity and level of experience in Australia increases.

Despite a higher rate of capital cost reduction than wind, the overall rate of reduction in levelised costs does not show a marked difference compared to wind because capital costs contribute less to overall costs than in the case of wind farms. This is primarily due to the assumption that transmission costs are higher for geothermal plant.

Geodynamics states that operating costs for geothermal plant are in the order of $10-20/MWh (depending on scale) and relate mainly to the costs of pumping water through an underground heat exchanger and the maintenance of an above ground geothermal power plant. In MMA's modeling, $15/MWh is assumed.

Interest during construction is assumed to be slightly higher than some of the other renewable technologies (1 percentage points higher), since it can take several years to drill wells. The degree of uncertainty associated with the geothermal cost estimates presented here is likely to be comparatively high, since a fully commercial HDR plant has yet to be built in Australia (although construction and drilling work has commenced on demonstration plants).

Table B-4: Parameter values for geothermal energy

Parameter	Units	Value	Change from 2005 to 2050
Size	MW	50.0	Unchanged
Life	Years	17	Unchanged
Real pretax WACC	%	9.0%	Unchanged
Capacity factor		0.80	Increase from 0.80 in 2005 to 0.85 in 2020 and remains constant
Interest during construction	%	10.0%	Unchanged
Fuel costs	$/MWh	0.0	Unchanged
O&M costs	$/MWh	15.0	Unchanged
Ancillary service costs	$/MWh	0.0	Unchanged
Transmission costs	$/kW	250	Unchanged