Report to

The Climate Institute

A comparison of emission pathways and policy mixes to achieve major reductions in Australia's electricity sector greenhouse emissions

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ABBREVIATIONS

CCS	Carbon capture and storage
ETS	Emissions trading scheme
GWh	Gigawatt hour
IEA	International Energy Association
IGCC	Integrated gasification combined cycle
MMA	McLennan Magasanik Associates
MRET	Mandatory Renewable Energy Target
NGGI	National Greenhouse Gas Inventory
NRET	NSW Renewable Energy Target
RD&D	Research, development and demonstration
REGA	Renewable Energy Generators of Australia
REMMA	Renewable Energy Market Model Australia
RET	Renewable Energy Target
ST	Solar thermal
STEM	Short Term Electricity Market
SWIS	South West Interconnected System
TWh	Terawatt hour
UCC	Ultra clean coal
VRET	Victorian Renewable Energy Target
WACC	Weighted average cost of capital
WEM	Western Australian Electricity Market

EXECUTIVE SUMMARY

The Australian government is set to introduce an emission trading scheme (ETS) which it plans to commence in 2010. Although the government has released a Green Paper outlining the parameters for the design of an emission trading scheme, one of the key debating points is around the caps on emissions, particularly over the medium term. On the one hand, there are calls for a soft start to provide appropriate investment signals for low emission technologies, but not put Australia too far ahead of global action. On the other hand, there are calls for decisive action to drive absolute reductions in emissions and for the national target to be calibrated towards driving an ambitious global response. A second debating point is about the role for complementary measures such as energy efficiency targets and an expanded renewable energy target. Some argue that such measures will be superfluous once an emission trading scheme is in place, whilst others argue that emissions trading would, of itself, not overcome the many market failures that inhibit uptake of low emission technologies, and that removing the complementary measures will increase the cost of abatement on the economy.

The Climate Institute commissioned MMA to examine these debating points. Using a simulation model of Australia's electricity markets, MMA estimated the benefits and costs of alternative trajectories, or pathways, for emission caps and for a range of complementary measures. The "benefits" mainly related to the level of abatement of greenhouse emissions and accelerated technological development. The "costs" covered the additional capital, fuel and operating costs involved in bringing on low emission technologies and in altering the natural merit order in the dispatch of generating plant.

To illustrate the major points of the debate, a number of scenarios were developed including:

- *Reference scenario*: No cap on emissions
- *Early action with ETS only scenario*: Early action trajectory in emission cuts using emissions trading only. This involves cuts in emissions from 2011 in a linear trajectory to the ultimate cap of 80% of 1990 emissions in 2050.
- *Early action plus energy efficiency scenario*: Early action trajectory in emission cuts, with additional measures to encourage energy efficiency to reach and maintain improvements at the OECD average by 2020. (This is approximately double the long-term trend improvement in energy efficiency projected by macro-economic models.)
- *Early action plus energy efficiency and renewable energy target scenario:* Early action trajectory, with additional measures to encourage energy efficiency to reach and maintain improvements at the OECD average, plus a 45,000 GWh renewable energy target by 2020.
- *Early action plus energy efficiency and renewable energy target and government support for early adoption of CCS and solar thermal scenario:* This is the same as the early action plus

energy efficiency and renewable energy target scenario, but with additional government support for demonstration and early deployment of carbon capture and storage as well as for new renewable technologies, such as solar thermal.

- *Soft start scenario:* Delayed action emission trajectory, but a $15/t CO_2e to $35/t CO_2e carbon price signal in the period from 2010 to 2020 which acts as an early signal to carbon constraints. This scenario is meant to mimic a possible soft start.
- *Soft start plus energy efficiency and renewable energy target scenario:* The long-term target under the Soft start scenario is assisted by an energy efficiency program to achieve and maintain an OECD average rate of energy efficiency and a 45,000 GWh renewable energy target.
- *Soft start plus energy efficiency and renewable energy target and government support for early adoption of CCS and solar thermal scenario:* This is the same as the previous scenario, but includes additional government support for demonstration and early deployment of carbon capture and storage as well as for new renewable technologies, such as solar thermal.

The analysis focuses on the electricity market only. Although the government proposes an expansive emission trading covering other sectors, the electricity market is likely to be a major component. This is because 35% of all emissions currently come from this sector, emissions are growing faster in this sector than in others, and the proposed exclusion of sites with emissions less than 25 kt CO_2e means that emissions from electricity generation are likely to form over 50% of the total emission pool under an emission trading scheme. The analysis is designed to provide insights on the key issues.

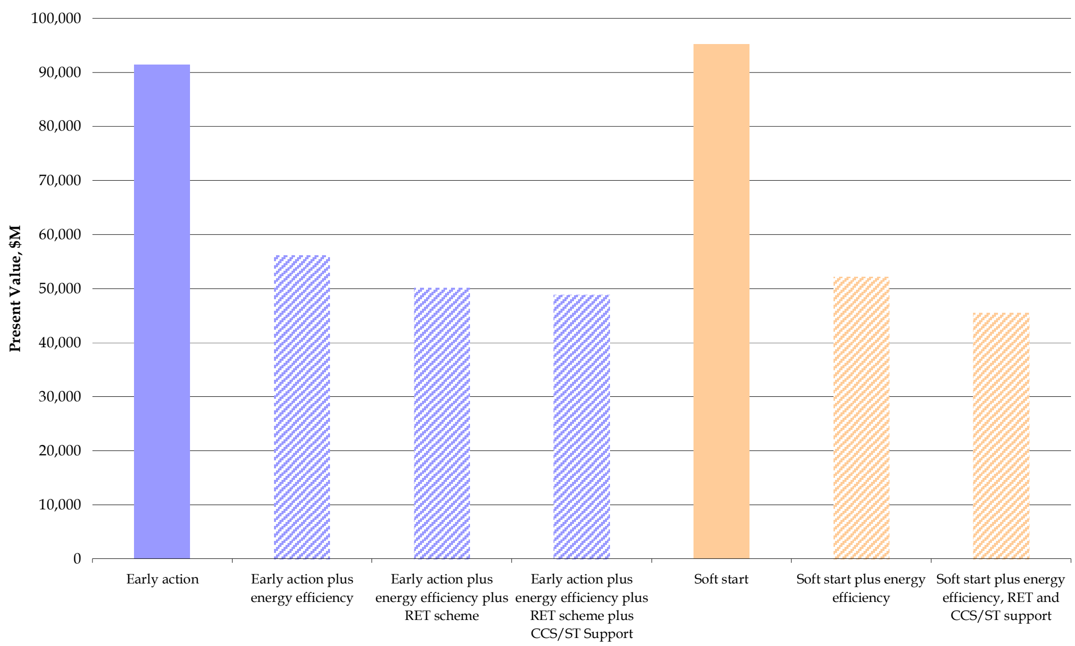
All scenarios modelled lead, by design, to the same cumulative abatement of greenhouse gases by 2050. The trajectories, however, differ. Even with a modest carbon price cap, emissions are likely to be only stabilised, rather than fall in the period to 2020 under the soft start scenario. By 2020, only 16 Mt CO_2e of emissions from combustion of fuels in electricity generation have been abated, which is about 8% of current emissions from that sector. Under this scenario, emissions would be around 3% above today's levels. In the early action scenario, by comparison, some 68 Mt are abated, or around 34% of current emissions from the electricity sector. The main difference between the two scenarios is that the reduction in emissions under the soft start scenario is very sharp after 2020, and the level of emissions much lower after 2020 than under the early action scenario, in order to meet the cumulative target. This implies that future generations would bear the burden of reducing emissions if action is delayed.

Reducing emissions will increase the costs of the resources (capital, fuel and labour) deployed in electricity generation. Resource costs for each scenario have been estimated assuming a range of discount rates which reflect the divergence of views on the discount rates that should be used for analysis of long-term costs and benefits.[1] As shown in

[1] Please note that all monetary values used in this study are in mid 2007 dollar terms.

Figure E-1, resource costs for the soft start and early action scenarios are similar. This implies that the economic costs are similar whether there is a soft start or whether early action is taken. (The soft start scenario is around $4 billion more expensive than the early action scenario.) Although early cuts in emissions require more expensive low emission generation options to be deployed early, delaying the cuts involves even more expensive investment in new generation from 2020 onwards. Delaying cuts may also lock in relatively higher emission plants in the period before deep cuts are enforced, although the presence of a modest carbon price on emissions provides enough incentives to prevent entry of new high emitting plants. Early action may also accelerate cost reductions through learning by doing.

Figure E-1: Present value of resource costs of measures with discount rates declining over time



This analysis does not consider the costs and benefits of early action that are not easily captured in simulation models, such as, the ability to influence international climate talks and participate in new and rapidly growing markets for low emission technologies and goods and services.

The finding that economic costs are likely to be similar under soft start and early action scenarios depends on a number of key assumptions. These are that:

- The same level of cumulative emissions is achieved under both the soft start and early action scenarios. In this analysis, this was done to enable comparison and because the adverse impacts of climate change depend on the <u>stock</u> of carbon in the atmosphere. By enforcing the same cumulative target, the long-term benefits from reducing the stock of carbon is the same for both scenarios.

- The modest carbon tax in the soft start scenario, in the period before 2020, causes investors to switch away from new conventional coal fired plant. If carbon prices are not high enough, there is a risk that more new coal plant would be deployed in some states, making it more difficult (requiring a higher permit price) to achieve the given targets beyond 2020.

- Cost reductions through learning by doing is possible. Cost reductions in the early action case are accelerated due to learning by doing. The cost reductions are eventually achieved in the soft start scenario, but at a later date, which reduces the present value of the reductions.

The analysis indicates that complementary measures, if designed properly, could also reduce the resource costs from emissions trading (see Figure E-1). Energy efficiency programs are likely to lead to the largest decrease in resource costs from emissions trading, although this finding is based on estimates on the amount of energy savings that can be made through energy efficiency, and the presence of market failures that prevent those savings being realised under current market arrangements.

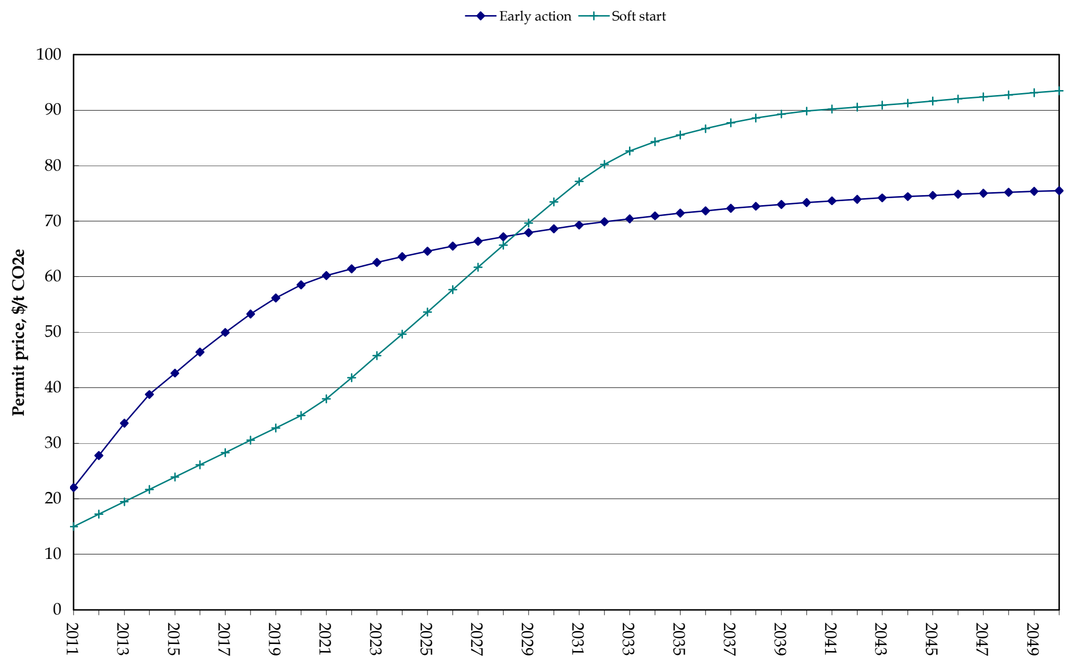
A renewable energy target could also lead to lower resource costs, depending on the extent of cost reductions through learning by doing. Other commentators have argued that such cost reductions are not likely to occur in Australia. However, recent industry experience in Australia and around the world is at odds with these conclusions. Other economists and analysts such as those at the International Energy Agency (IEA) have noted that the extent of market failures in the electricity generation sector supports the extensive development and initial deployment of new technologies by governments.

Under a fixed carbon price regime, a renewable energy target can lead to earlier entry of new renewable plant than would have occurred otherwise, increase the level of early abatement, and reduce the level of abatement required later on.

Emissions trading will also have major distributional impacts. Purchasing permits to emit will increase the costs of electricity generation, and some of this increased cost will be passed onto customers. Permit prices under the soft start and early action scenarios are shown in Figure E-2, indicating prices could reach as high as \$95/t CO_2e.[2] Permit prices are higher for the early action scenario in the period up to 2028, but then become lower as the extent of cuts required in the soft start scenario are realised.

2 These permit prices are likley to be higher if the emission trading scheme is extended to other sectors of the economy.

Figure E-2: Permit prices



As a result of these permit prices, electricity prices to customers are likely to increase under the early action scenario by between 55% to 75% from 2020 onwards. This is shown in Table E-1. Obviously, the price increases to 2020 are lower for the soft start scenario, but this is outweighed by slightly higher prices over the long-term.

Again, the price increases are moderated by the implementation of complementary measures, particularly energy efficiency programs. Implementation of technology deployment measures could also reduce prices, but at a modest level, and only if cost reduction through learning by doing can be achieved.

Table E-1: Retail electricity price increases

	2010-2020	2021-2030	2031-2040	2041-2050
Early action	67%	68%	75%	55%
Early action plus energy efficiency	64%	57%	57%	39%
Early action plus energy efficiency plus RET scheme	58%	57%	59%	36%
Early action plus energy efficiency plus RET scheme plus CCS/ST support	50%	53%	57%	34%
Soft start	40%	72%	76%	62%
Soft start plus carbon price and energy efficiency	37%	67%	70%	58%
Soft start plus carbon price and energy efficiency plus RET scheme plus CCS/ST support	31%	50%	61%	41%

Overall, the main findings of this study are:

- Soft starts may not necessarily lead to better long-term economic or environmental outcomes and risk worse economic outcomes. Depending on the level of cost reductions possible through early entry of new technologies and/or the extent to which lock in of high emitting technologies is prevented, economic outcomes may be better with early action, as long as the long-term goal is to reduce emissions. The justification for a delayed start will therefore depend on other reasons, such as the ability of the economy to gear up for the investments in low emission technologies, and would need to be balanced against the inherent risks of delaying action to reduce emissions.

- Complementary measures could ease the economic burdens of emissions trading. As long as estimates of the energy efficiency potential are realised, implementation of programs to overcome market failures inhibiting adoption of energy efficient appliances and production processes could have a large impact on reducing the cost of emission trading. Technology deployment measures could also help reduce costs, but only if learning by doing occurs as a result of the early deployment. These measures are important in either a soft start or early action scenario, as they enable technology development.

1 INTRODUCTION

Electricity generation is the largest single source of greenhouse gas emissions in Australia. In 2004, emission from fuel combustion in the generation of electricity amounted to around 195 Mt, or 35% of net national emissions. Electricity generation is also the fastest growing source of emissions, with emissions in 2004 being 51% higher than in 1990. Rapid growth in electricity demand and an increase in coal-fired generation were the main factors responsible for the fast growth in emissions.

With growth in electricity demand projected to continue at just below 2% per annum, emissions will continue to grow in the absence of further measures to curb them. Previous analysis undertaken by MMA suggests that emissions during the first Kyoto commitment period (2008-2012) are likely to be about 50% to 60% above 1990 levels. Beyond 2012, emissions are will likely to continue to increase, albeit slowly at first as a result of the proposed expanded Renewable Energy Target. By 2030, electricity generation could be the major source of emissions in Australia.

The Climate Institute is exploring the potential impacts of a range of caps to curb emissions from electricity generation. MMA has been contracted to undertake a study of potential options for reducing emissions to meet the caps, including estimations of how meeting the caps will impact on the electricity market and resource use. Preliminary results of this work were reported in May 2007.[3] The information provided by this study finalises this assessment after expert review and will be used to inform the debate on greenhouse and energy policies. In particular, this report analyses the cost effectiveness of a range of policy measures to meet particular targets and explores whether it is better to take early action or delay cuts in emissions.

The objective of this study was to model the impacts of a range of emission trajectories to an ultimate target of 80% below 1990 levels by 2050. In the long-term, the electricity sector would be expected to contribute more to a given national target than other sectors. This is due to the fact that this sector has many known and prospective emission reduction options. As such, this sectoral 80% reduction in emissions would be broadly consistent with a national target of a 60% reduction in emissions by 2050. Although each trajectory has different inter-temporal targets, the cumulative level of abatement by 2050 is the same for all trajectories. This "carbon budget" approach is broadly consistent with that proposed by the Garnaut Review of Climate Change.[4]

A combination of bottom up models were used to determine the impacts of different scenarios on electricity prices, greenhouse gas emissions, capital investments by technology type, and the cost of resources used in electricity supply. The analysis covered the period 2008 to 2050.

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[3] The Climate Institute (2007), *Making the Switch: Australian Clean Energy Policies*, Preliminary Research Report, Sydney, May.

[4] Garnaut Climate Change Review (2008), *Draft Report*, Melbourne, June.

The focus of the analysis was on the three major grids in Australia: the National Electricity Market (NEM), the South West Interconnected System (SWIS) and the Darwin Katherine Grid. Emissions from electricity generation in these grids comprise over 95% of total emissions from electricity generation and will be the largest source of growth in emissions from electricity generation. Generation in other smaller grids is already based on low emission technology.

Please note that monetary values are in mid 2007 dollar terms, unless otherwise stated.

2 METHODOLOGY

Rigorous modelling of the market impacts resulting from meeting caps on carbon emissions requires modelling of the key features of the energy markets in Australia and the economic interdependence between various sectors of the economy and the energy markets.

The energy markets in Australia have become increasingly integrated. Restrictions on interstate trading of electricity and gas have been removed, allowing the development of new gas and electricity systems between states. The availability of large sources of gas in the north west of Western Australia and the Timor Sea could also lead to development of gas transmission systems to the eastern seaboard markets over the long-term.

With the establishment of integrated markets, factors affecting the electricity or gas markets in one region will impact on the markets in other regions. Factors affecting gas prices also impact on electricity prices. Trends in gas prices will also impact on the structure of the electricity generation sector.

Thus, a method to project impacts of emission caps requires modelling of the integrated energy markets in Australia. The method needs to account for the economic relationship between the electricity and gas markets and the competitive structure of the wholesale markets in electricity. The economic relationships impact on the level of dispatch of each generating plant in the electricity market, thus affecting the level of emissions and the wholesale price to customers.

In this study, a suite of models was used to determine the impacts of the scenarios on the uptake of new technologies. The models used were:

- A probabilistic simulation model of the electricity markets. The model simulates the dispatch of generating plant, based on the bids and availability of the plants. The simulation model was used to calculate electricity generation costs (capital, fuel and operating costs), wholesale and retail electricity prices, and emissions.
- A dynamic model of the uptake of renewable energy technologies, MMA's REMMA model, was used to determine the impact of carbon prices on the uptake of new renewable energy technologies.

The models are used iteratively to arrive at a rigorous set of estimates of the impacts of the carbon caps.

The general approach was to utilise MMA's electricity and renewable energy market models to account for the interrelationships between these markets over the study period. Electricity prices were determined by the marginal cost or bid of the last plant dispatched. Emissions from electricity generation were determined by assigning emission intensities to each of the generating units represented in the electricity model.

The models depict each of the entities operating in the market such as each generating plant in the electricity models and each renewable energy generator in the renewable energy model. The models account for interactions amongst market participants based on the relative costs of production, the marginal costs of generation units and market power of the firms involved.

There are three major electricity markets in Australia:

- The National Electricity Market (NEM), which covers the integrated grids of Queensland, New South Wales, Victoria, South Australia and Tasmania.
- The South West Interconnected System (SWIS), which covers the grid in the south west of Western Australia, supplying the load centres of Perth, Kwinana and the Kalgoorlie region.
- The Darwin-Katherine Interconnected System (DKIS) Grid in the Northern Territory.

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

- Chronological hourly 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 plant is assumed to shadow bid to maximise revenue at times of peak demand).
- A range of bidding options for thermal plant where an auction market exists, (including fixed prices, shadow bidding, and average price bidding).
- 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.
- Demand side bidding and interruptible loads as a dispatchable resource.

Average hourly pool prices are determined within the model based on thermal plant bids that are derived from marginal costs or entered directly. The model 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. The prices are solved across the regions of the market 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 patterns.

Reserve margin, loss of load hours and plant dispatch is determined for each electricity market.

New plant requirements, whether to meet load growth or to replace uneconomic plant, are chosen to ensure that:

- Electricity supply requirements are met under most contingencies. The parameters for quality of supply are determined in the model through the loss of load, energy not served and reserve margin. We have used a maximum energy not served of 0.002%, which is in line with planning criteria used by system operators.
- Revenues earnt by the new plant equal or exceed the long-run average cost of the new generator.

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.

Because the electricity market models include all generating units, changes to the cost of electricity supply can be modelled. Capital, operating and maintenance costs, and fuel costs are modelled in detail. Changes to the electricity supply cost from different technological pathways can then be calculated as the difference in system costs between the scenarios modelled.

Wholesale electricity costs delivered to customer transmission or distribution points are projected. This comprises the spot market price for electricity plus the marginal loss factors for transmission and distribution. It does not include network charges, any state government charges, or retailer mark-ups.

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

- 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, start-up times and ramping rates.
- 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.
- Annual hydro energy and allocation of generation on a monthly basis.
- Separation of hydro generation into run-of-river and discretionary.
- Capital costs for new generating plant.

The period of analysis is the period commencing 2007/08 and ending in 2049/50.

3 ASSUMPTIONS

Detailed assumptions for each of the electricity grids modelled are provided in Appendices A to C. A summary of the key assumptions is provided below.

3.1 Structural assumptions

Some major structural assumptions used in the modelling follow. These were that:

- Current institutional arrangements remain largely intact. The current structure of government owned enterprises in electricity generation also does not change.

- Options to meet growth in demand for electricity are selected on the basis of minimum costs, except in the scenarios where choices of technology are constrained. That is, the least cost option is chosen to meet the demand growth, selected from new generation and additions to the interregional transmission network.

- In competitive markets, there is price competition by generators. That is, generating companies price generation according to the marginal cost of the next highest cost generation. Peaking plant bid up to the offer price of demand management options. Renewable generation options are assumed to bid in at a level to ensure dispatch and therefore never set the price. Such plants effectively shadow the marginal cost of the thermal plant they displace.

- Generators do not operate high cost plant if they cannot recoup avoidable costs of that plant. Plants that cannot recoup avoidable costs are mothballed.

3.2 Electricity demand

Projections for electricity demand are based on published projections by the relevant authorities in each of the key markets (NEMMCO, The WA Independent Market Operator and the NT Utilities Commission). MMA's projections differ from those developed by the electricity market authorities in the following manner:

- Our projections include embedded generation, particularly the renewable energy generation supplied under the MRET scheme, and on-site embedded generation where some of this generation is likely to be traded in the wholesale markets. MMA includes the renewable energy component because MMA provides its own projections of renewable energy generation for each market. On-site generation is included because there is a prospect for an increased role for this generation in competitive markets.

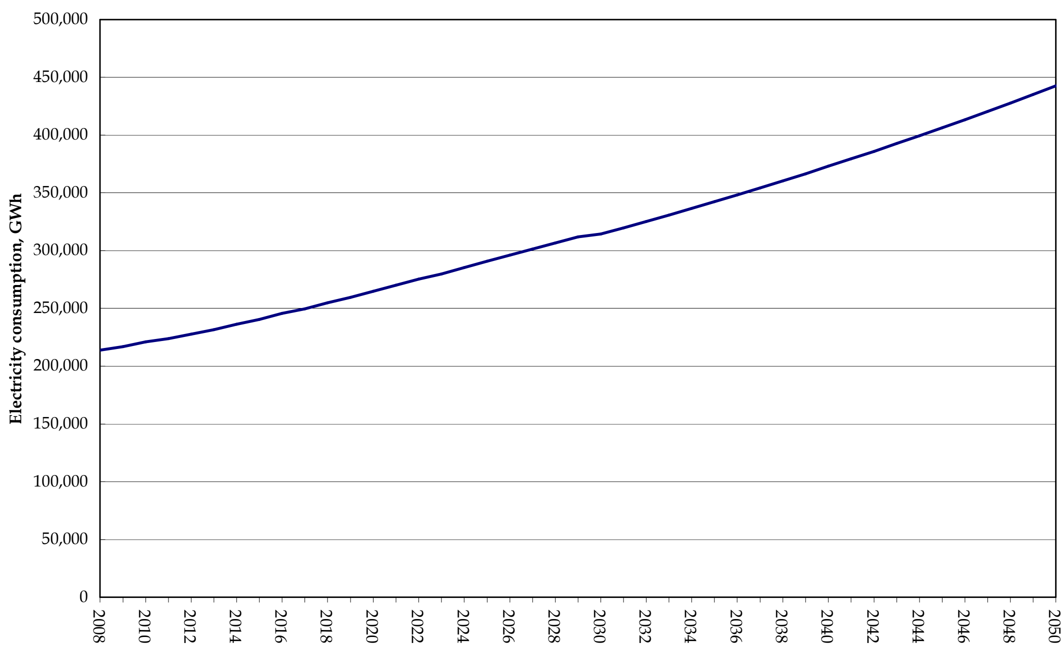
- MMA has subtracted demand to account for the impact of the state and federal governments' suite of energy efficiency policies, with the exception of the ban on incandescent light globes, which would be expected to have a small impact on electricity demand.

- We have reduced the long-term growth rate after 2015/16, to reflect the gradual decline in the GDP growth rate due to population aging, as forecast by the Federal Treasury.

The demand projections are shown in Figure 3-1. Electricity generation is projected to grow from 213 TWh in 2007/08 to 442 TWh in 2049/50. Growth is projected to be strongest in Western Australia and Queensland.

However, growth rates in electricity demand are projected to decline over time in most states. On average, growth rates are expected to fall from around 2.3% per annum in 2005/06 to 1.7% per annum in 2049/50.[5] The forecast rates of growth vary in the period to 2020, but show a declining trend thereafter. The variation in annual growth rates to 2020 reflects cycles in underlying assumptions, such as economic and population growth rates. After 2020, long-term trend growth rates in these variables were assumed so there are no cycles in the forecast electricity demand for this later period

Figure 3-1: Electricity demand projections, GWh, sent out basis



3.3 Generation cost assumptions

This section discusses generation assumptions made about plant availability, marginal costs, the entry of new generation capacity, new generation costs, emissions intensities, and carbon storage.

5 The declining rate of growth is consistent with a trend decline in the energy intensity of the economy. Thus, the rate of growth in electricity demand, relative to the rate of growth in the economy, falls over time.

3.3.1 Plant availability

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 98%.

3.3.2 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. MMA has also included, for open cut mines that are owned by the generator, the net present value of changes in future capital expenditure that would be driven by fuel consumption. This applies to coal in Victoria and South Australia. The indicative variable costs for various thermal plants are shown in Appendix B.

3.3.3 Entry of new generation capacity

In this section, there is an outline of the assumptions about existing plants being upgraded for additional generation capacity, then a description of assumptions about new plant generation capacity.

3.3.3.1 Upgrade potential for existing plant

Loy Yang Power has announced its intention to increase the capacity of Loy Yang A up to 2,236 MW, with some units rated at 570 MW. Macquarie Generation has announced plans to increase the capacity of the Bayswater units to 700 MW and has canvassed the possibility of further enhancement to 750 MW, although at greater expense. The same upgrade potential is assumed to be available at the other 660 MW units in NSW (Mt Piper, Eraring and Vales Point).

In all scenarios, it is assumed that existing coal plant continue to be refurbished to maintain output and efficiency to an economic life of 60 years, or to a time when fuel supplies run out. The model allows for the choice of the plant to be repowered at the end of their economic life under the following constraints:

- For most of the existing sub-critical pulverised fuel plant, space will not permit the plant to be upgraded with supercritical or ultra supercritical boilers. The latter boilers are much larger than the typical subcritical boiler. Thus, repowering is limited to integrated gasification combined cycle (IGCC) technology, whereby a gasifier, gas turbines and steam generators replace the subcritical boiler. This IGCC technology is likely to become competitive with existing technologies from 2020 onwards.

- Repowering does not occur unless the long-run average cost of the technology is lower than other alternative generation options.

- Repowering is limited for existing brown coal generators because of limited fuel resources. The economic life of the existing power station in Victoria is likely to be limited either by the economic life of the generating unit or the level of reserves of brown coal at the associated mine. Development of a new brown coal deposit will most likely require development of a new mine mouth power station as it is difficult to transport brown coal to distant power stations.

3.3.3.2 New generation – fossil fuel options

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.

In the longer term, new technologies with low or no emissions are likely to be adopted. This includes integrated gasification combined cycle technology, using coal as a fuel, and more efficient natural gas fired combined cycle plant.

MMA has 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 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 – 8% pa.
- Construction period - 3 years for coal fired plant, 2 years for CCGTs.

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 data provided in published documents. Key assumptions behind the analysis are listed in Table 3-1. The data are representative of 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 plants 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.

Table 3-1: Technology costs and performance assumptions, mid 2003 dollar terms

Option	Life	Auxiliary load	Sent-out capacity	Capital cost, 2010	Capital cost de-escalater, 2010 to 2020	Capital cost de-escalater, 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	8	690	1,677	0.5	0.5	9.6	0.48	3	30
Ultra supercritical coal	60	8	690	2,012	0.5	0.5	8.7	0.48	3	38
IGCC	30	22	554	2,385	2.0	1.0	9.1	1.20	2	44
IGCC with CC	30	25	473	3,291	2.5	1.0	11.4	1.30	3	50
Ultra supercritical with CC and oxyfiring	60	30	525	2,674	1.0	0.5	12.0	0.58	3	33
USC with post-combustion capture	35	19	608	2,215	2.5	0.5	12.9	0.58	4	33
Brown Coal Options										
Supercritical coal with drying	60	12	636	1,759	0.5	0.5	9.2	0.48	5	43
Supercritical coal	60	8	665	2,018	0.5	0.5	10.4	0.48	5	35
Ultra supercritical coal with drying	60	12	636	2,111	2.0	0.5	8.8	0.48	5	45
IGCC with drying	30	18	430	2,169	2.0	1.0	9.5	1.20	4	49
IDGCC	30	18	458	1,875	1.0	0.5	9.2	1.20	6	60
IGCC with CC and drying	30	22	400	3,092	2.5	0.5	12.0	1.30	5	55
IDGCC with CC	30	20	416	2,700	1.5	0.5	10.8	1.30	5	70
Natural gas										

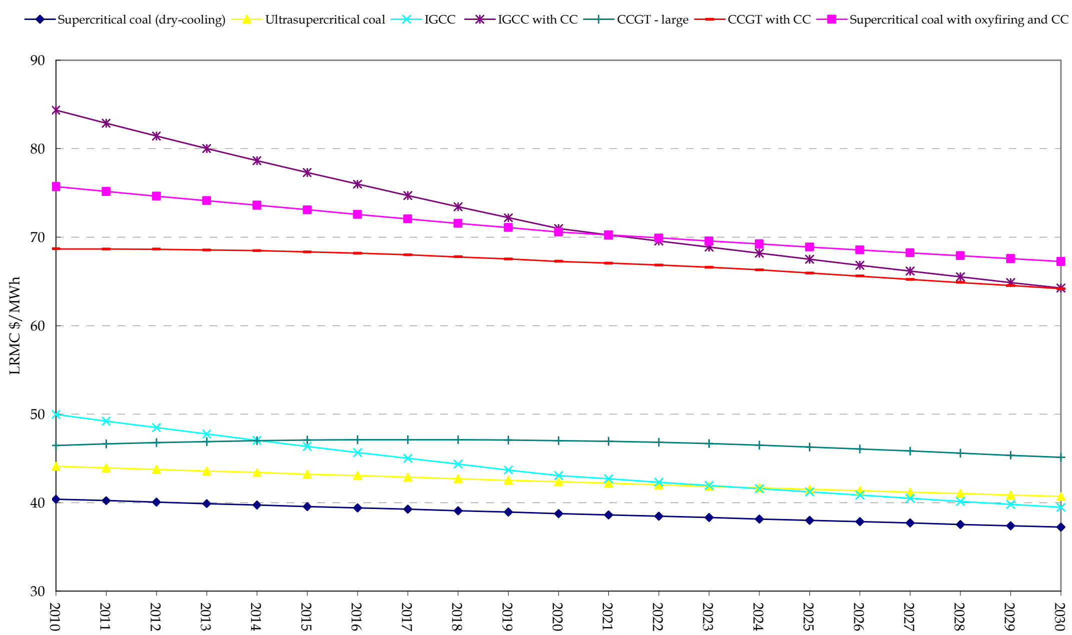
Option	Life	Auxiliary load	Sent-out capacity	Capital cost, 2010	Capital cost de-escalater, 2010 to 2020	Capital cost de-escalater, 2021 to 2030	Heat rate at maximum capacity	Efficiency improvement	Variable non-fuel operating cost	Fixed operating cost
	Years	**%**	**MW**	**$/kW so**	**% pa**	**% pa**	**GJ/MWh**	**% pa**	**$/MWh**	**$/kW**
CCGT - small	30	2	235	1,309	0.5	0.5	7.4	0.60	3	22
CCGT - small	30	2	47	1,833	0.5	0.5	7.8	0.60	4	25
CCGT - large	30	2	490	1,190	0.5	0.5	6.8	0.60	3	20
Cogeneration	30	2	235	1,553	0.5	0.5	5.0	0.60	3	20
CCGT with CC	30	10	450	1,785	1.0	0.5	7.9	0.70	4	40
Renewables										
Wind	25	1	99	1,822	2.0	0.5		0.20	2	35
Biomass - Steam	30	6	28	2,318	1.0	0.5	11.5	0.10	4	50
Biomass - Gasification	25	10	27	2,484	2.0	1.0	11.0	0.10	5	50
Concentrated Solar thermal plant - solar thermal assist	25	1	99	4,100	3.2	2.0				50
Geothermal - Hydrothermal	30	8	46	2,987	1.0	1.0	11.0	0.10	3	70
Geothermal - Hot Dry Rocks	25	10	45	4,153	2.0	1.0	12.0	0.10	3	70
Concentrating PV	30	3	97	2,700	1.0	1.0		0.10		
Nuclear	50	10	900	2,900	1.0	0.5	9.5	0.10	10	70

Note: Plant capacity, efficiency and cost data based on a sent out basis.

The long-run average cost assumed for each technology in NSW is shown in Figure 3-2. The trends indicate that current technologies are likely to remain the preferred option, on cost grounds, unless carbon prices are imposed.

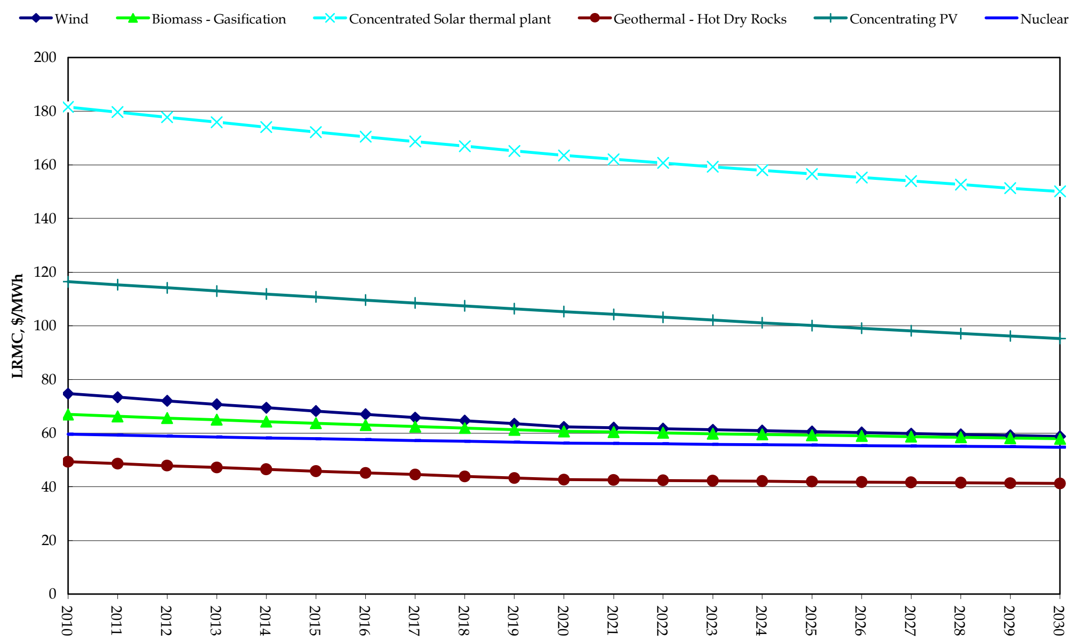
Gas fired plant for base load duty is likely to be of higher cost than for coal plant operating on base load duty. The principle cause for this is the assumed increase in gas prices. Gas prices are expected to rise in the long-term as a result of increasing gas demand and the increasing cost of supply as gas needs to be sourced from more remote fields.

Figure 3-2: Trends in long-run marginal costs for generating technologies, fossil fuel technologies, NSW, $/MWh



Note: Levelised costs were calculated using the previously listed assumptions, for a capacity factor of 90%.

Figure 3-3: Trends in long-run marginal costs for generating technologies, renewable energy and nuclear technologies, NSW, $/MWh



Note: These long-run marginal cost estimates do not include the costs associated with new network infrastructure such as transmission lines. However, in the full modelling exercise these costs are included.

3.3.4 New generation costs – renewable generation

Renewable generation costs were based on data published in previous MMA reports. The key assumptions are shown in Table 3-1 and Figure 3-3.

PV generation was not considered in the analysis. The cost of PV generation is projected to decline to around $200/MWh by 2030, which is comparable to the 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, which will only be partly compensated by sales of energy to the grid. Public investment in network grid upgrades could alter this assumption.

The amount of renewable generation able to be bid into the market was also limited, as generation costs are expected to rise above those shown in Figure 3-3 as wind farms are increasingly located in more remote or less windy areas and as biomass plant sources more remote fuel. Based on previous analysis undertaken by MMA, the total amount of commercially accessible new renewable generation resource was limited to 184,000 GWh above current levels by 2050.

Table 3-2 shows assumed renewable energy resource capacity by type, by state, for 2050.

Table 3-2: Renewable energy resources by technology type and state, 2050, GWh

	Qld	NSW	Vic	Tas	SA	WA	NT
Agricultural Waste	2,288	1,709	2,231	0	0	1,646	0
Bagasse	3,084	0	0	0	0	45	0
Black Liquor	0	0	136	0	0	0	0
Landfill Gas	48	116	83	0	0	0	0
Municipal Solid Waste	280	300	232	425	105	619	0
Sewage Gas	0	0	0	26	0	0	0
Wood/Wood Waste	97	1,380	403	202	1,681	4,252	0
Wet waste	22	22	20	0	15	11	0
Geothermal	30,555	27,855	6,359	0	14,786	0	0
Hydro-electric	52	263	35	451	0	0	0
SHW	0	0	0	0	0	0	0
Solar/PV	6,762	6,554	5,706	0	4,557	5,117	3,045
Wave	0	0	5	0	0	0	0
Wind	4,175	11,021	18,067	2,899	11,705	3,094	0

Notes: Generation refers to the potential generation from new (yet to be constructed) projects. Geothermal refers to hot dry rocks potential only. Hydro-electric potential refers to upgrades at existing facilities (through turbine upgrades and modifications) and new mini hydro-electric facilities. Solar/PV covers photovoltaic, concentrated solar photovoltaic and solar thermal technologies.

Exhibit 3-1: Learning by doing assumptions

The impact of complementary measures on learning by doing has been estimated in this analysis. With accelerated uptake of low emission energy technologies, cost reductions are possible through learning by doing.

The approach adopted here is similar to the approach adopted in a recent study undertaken by MMA.[6] This study's finding was criticised by the Productivity Commission[7] on a number of grounds, as follows:

- The case for market failure to support complementary measure mandating the uptake of renewable energy technologies is weak.
- In the study for Renewable Energy Generators of Australia (REGA), emission policy was modelled as an emission tax and did not take into account the crowding out effect of the complementary measure (that is crowding of other lower cost abatement options, such as combined cycle gas-fired generation).
- The learning by doing rates used by MMA for some technologies were over optimistic, because global learning by doing rates were applied to capacity uptake in Australia (which is only a small part of the global market) and because MMA used high estimates compared with some other estimates.
- The modelling did not factor in learning by doing in fossil fuel generation technologies.

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6 MMA (2007), *Increasing Australia's Low Emission Electricity Generation – An Analysis of Emissions Trading and a Complementary Measure*, report to the Renewable Energy Generators of Australia, 24 October 2007.

7 Productivity Commission (2008), *What Role for Policies to Supplement an Emission Trading Scheme*, Submission to the Garnaut Climate Change Review, May.

The Productivity Commission did not provide details as to why the case for market failures for supporting deployment of new technologies was weak. Other economists have noted the extent of market failures in the electricity generation sector and provide evidence for the extensive development and initial deployment of new technologies by governments.[8]

In the modelling for REGA, the carbon policy was modelled as if it were a carbon tax, which led to additional abatement in the period before 2020. Crowding out was partially modelled in that the electricity market can only take so much new capacity and additional low emission generation deferred the need for low cost combined cycle generation. In this study, the same cumulative targets in all scenarios have been modelled and hence the modelling has fully captured the crowding out effect in the electricity sector, although the potential crowding out of other low emission options in other sectors has not been captured.

Costs reductions for both fossil fuel and renewable technologies assumed in this study were similar to those used in the REGA study. The cost reductions applied only to capital costs and were modelled as a function of the increase in capacity. Further, the rates only applied to the component where reasonable development occurred in Australia. The cost assumed reduction rates were as follows:

- 10% reduction for every doubling of wind capacity. This was applied to 30% of the capital cost. This is conservative in that it does not recognise the substantial learning that has occurred in Australia as a result of the different wind regimes in this country compared to Europe, where much development of wind generation has occurred.
- 15% reduction for every doubling of biomass capacity, with this rate applied to 40% of the capital cost. The Productivity Commission criticised this rate as being too high relative to other overseas estimates. It should be pointed out that these rates do not apply to conventional biomass options such as steam boilers, but to the new pyrolosis and gasification technologies, in which Australia is a leading developer, including some new waste to energy technologies. Thus, the higher rates apply to these relatively immature technologies.
- 17% reduction for every doubling of capacity of geothermal and solar thermal technologies, applied to 60% of the capital costs. The Productivity Commission has argued that this was higher than estimated in overseas studies. The estimates for overseas studies were for conventional hydrothermal technology, for which there is limited potential in Australia and which is a relatively mature technology. The cost reduction in this study applied to hot rocks technology, which is under development and shows promise in Australia. Australia is in the forefront of development of this technology and the country has a comparative advantage due to the high concentrations of radioactive isotopes in Australia's land mass, which causes the heating of granitic rocks.
- Learning by doing in fossil fuel technologies was modelled for conventional components and for carbon capture and storage components. Based on IEA studies, the cost reduction rate for conventional technologies was set at 5% for every doubling of capacity (reflecting the maturity of these technologies), with this rate applied 50% of the capital costs. For carbon capture and storage components, a rate of 17% per doubling of capacity was applied to 50% of the capital costs (equivalent to the highest rate for renewable technologies).

The impact of complementary measures on learning by doing will depend on a large number of factors. There is an interplay between the impacts of learning by doing from complementary measures versus the cost on crowding out other low cost abatement options. It is this interplay which determines whether there is a net benefit to a technology deployment scheme.

[8] For example: IEA/OECD (2003), *Creating Market for Energy Technologies*, Paris; V. Norbergy-Bohm. (2000), Creating Incentives for Environmentally Enhancing Technological Change: Lessons from30 Years of US Energy Technology Policy, *Technology Forecasting and Social Change*, Volume 65, pp 125-148.

3.3.5 Emission intensities

Greenhouse gas emissions from the combustion process result from the conversion of carbon in the fuel to CO_2. The key parameters in determining the CO_2 emissions are the quantities and types of fuels used and the carbon content of these fuels. Carbon contents and combustion emission intensities for each type of coal and gas supplying electricity-generating facilities have been identified and incorporated into the electricity model. Emission intensities, for individual power stations, are supplied in the National Greenhouse Gas Inventory (NGGI) for years up to 2004 and these have been used as defaults where no further information could be identified.

3.3.6 Carbon storage for fossil fuels with CO_2 capture

The potential storage capacity for CO_2 is projected to be around 740 Gt, which is equivalent to around 1,300 years worth of storage at current national emission rates.[9] The states with the largest potential for storage include Victoria and Queensland, with these two states accounting for about half of the total storage potential. Western Australia, Northern Territory and Tasmania have adequate storage for their requirements. It is assumed that CO_2 captured in NSW may need to be piped to other states in the long-term.

3.4 Scenarios

The study is confined to the impacts on the electricity market. As such, the scenarios are limited by the fact that they do not factor in interactions between other parts of the economy and other carbon markets. For example, the permit prices presented do not necessarily reflect the carbon impost required to achieve a given level of abatement in the national economy. This will be influenced by the marginal costs of abatement in other sectors and the extent to which an Australian emission trading system is linked to global markets. A number of trajectories for emission caps were explored, but each led to the same cumulative emission cuts over the period to 2050.

Other important assumptions included:

- Coverage was confined to combustion emissions from electricity generation.
- No offsets were assumed.
- In some scenarios, other support measures were also assumed, including programs to promote further energy efficiency and measures to support the early deployment of low emission technologies.
- The targets were to be achieved through emission trading.

9 J. Bradshaw, G. Allinson, B.E. Bradshaw, V. Nguyen, A.J. Rigg, L. Spencer and P. Wilson, *Australia's CO_2 Geological Storage Potential and Matching of Emission Sources to Potential Sinks*, Energy 29, (2004), 1623-1631

Two emission trajectories were examined:

- Early action trajectory: Emissions cap declines linearly from 2007 levels to 80% cut from 1990 levels by 2050.

- Soft start trajectory: the enforced emission caps do not commence until 2020. However, a carbon price is imposed between 2010 and 2020, commencing at \$15/t CO_2e in 2010 and rising to \$35/t CO_2e in 2020. This could represent government imposing a safety valve or penalty in early years of the emissions trading system. Emissions decline sharply from 2020 to reach a final target of an 80% reduction from 1990 levels by 2050. By 2050, the cumulative level of abatement is the same as for the early action trajectory, implying a sharper level of cuts in emissions from 2020.

Based around these targets, six scenarios for modelling electricity market impacts were developed:

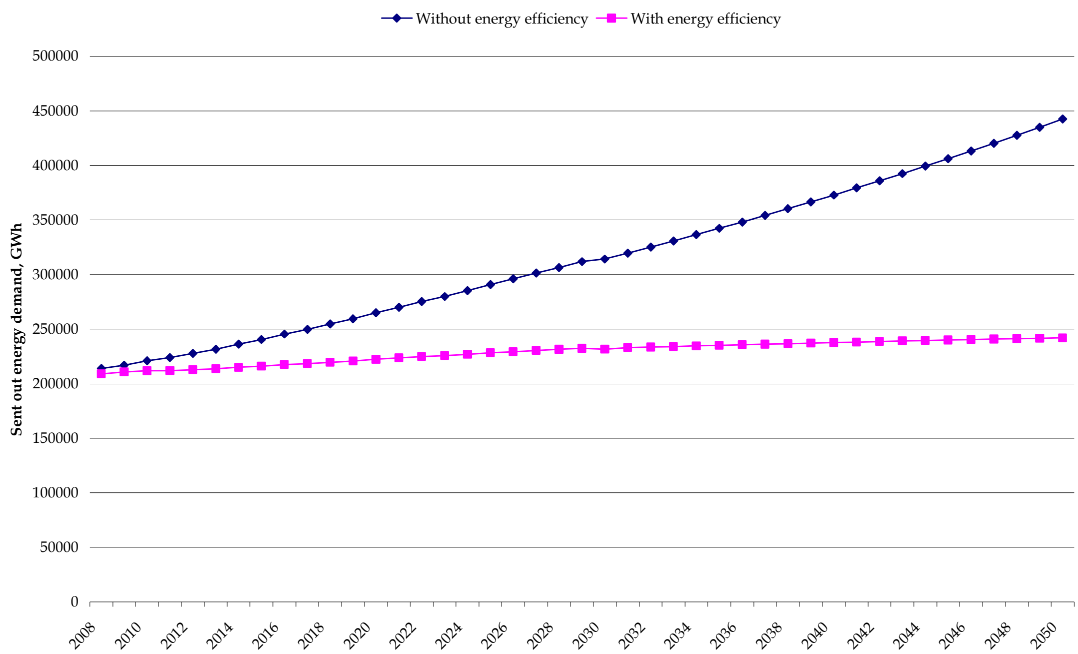
- *Reference scenario*: No cap on emissions

- *Early action, ETS only scenario*: Early action trajectory in emission cuts.

- *Early action plus energy efficiency scenario*. The government has committed to put Australia at the forefront of energy efficiency improvement among OECD countries. This leads to an early action trajectory in emission cuts, with additional measures to encourage energy efficiency to reach and maintain improvements at approximately double the long-term historical rate by 2020. Such a reduction could be achieved via direct government intervention to overcome barriers to energy efficiency uptake in other parts of the economy and/or a broad demand reduction driven by the emissions trading system causing the shift away from energy insensitive goods and services/technologies in the wider economy. Separate analysis by Energy Strategies suggests these demand reductions could be achieved with known technologies in the residential and commercial sectors alone.[10] Figure 3-4 compares demand growth under the reference scenario and energy efficiency scenarios.

[10] Energy Strategies Limited (2007), *Potential Electricity System Demand Reductions From Distributed Measures: Residential And Commercial/Services Sectors*, Report to The Climate Institute, May 18.

Figure 3-4: Demand reductions from energy efficiency



- *Early action plus energy efficiency and renewable energy target scenario:* The early action trajectory with additional measures to encourage energy efficiency to reach and maintain improvements at double historical rates, plus a 45,000 GWh renewable energy target by 2020. In preliminary analysis for The Climate Institute, a clean energy target, which included fossil fuels with carbon capture and storage as well as renewable energy as eligible technologies was modelled under this scheme.[11] However, further analysis, which included updated LRMC estimates for all technologies, found that given the high costs of fossil fuels with carbon capture and storage this measure does not pull forward the deployment of these technologies. For simplicity, the Clean Energy Target was replaced with a Renewable Energy Target and additional scenarios where developed to examine the impact of policies and measures that pull forward the deployment of new emerging low emission technologies (see below).

- *Early action plus energy efficiency and renewable energy target and government support for early adoption of CCS and solar thermal:* Additional government support for demonstration and early deployment of carbon capture and storage and new renewable technologies such as solar thermal is included. This includes 800 MW of coal with carbon capture and storage deployed by 2020 (400 MW in Victoria and 400 MW in Qld/NSW/WA) and 400 MW of concentrated solar thermal (with storage) in NSW and Western Australia by 2020.

[11] The Climate Institute (2007), ibid.

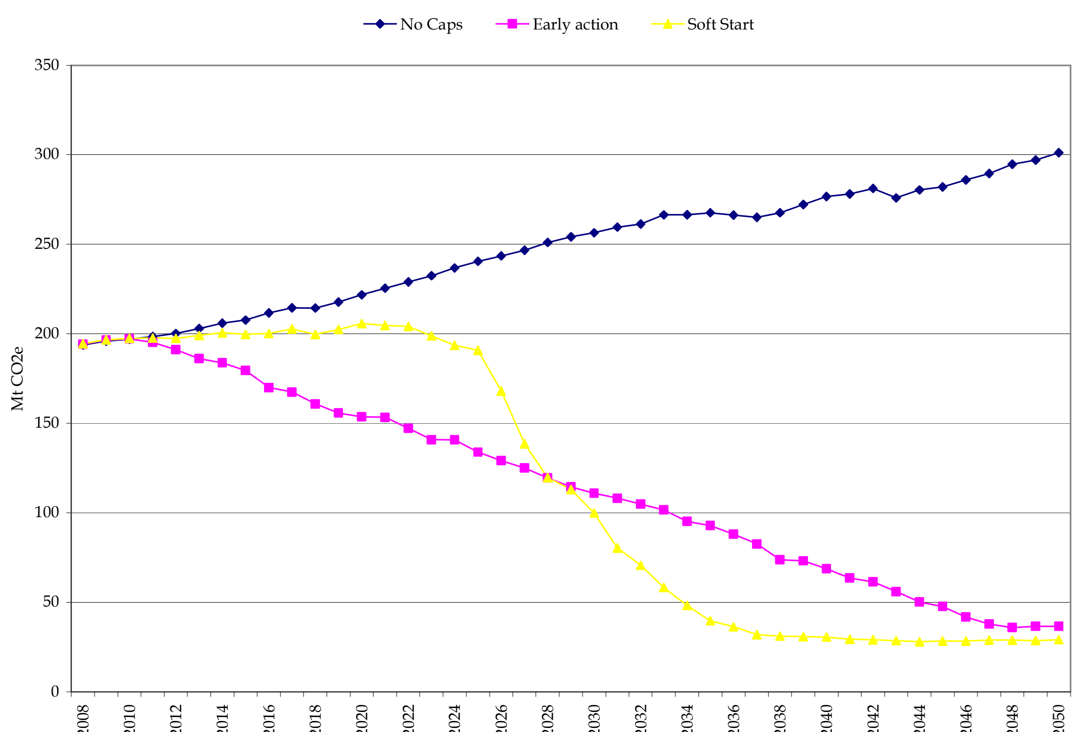
- *Soft start, ETS only, scenario.* This combines the delayed action emission trajectory, with a \$15/t CO_2e to \$35/t CO_2e carbon price signal in the period to 2010 to 2020, which acts as an early signal to carbon constraints.
- *Soft start plus energy efficiency and renewable energy target scenario:* Achieving the long-term target under a soft start scenario is assisted by an energy efficiency program to achieve and maintain double the historical rate of increase in energy efficiency and a 45,000 GWh renewable energy target.
- *Soft start plus energy efficiency and renewable energy target and government support for early adoption of CCS and solar thermal:* Additional government support for demonstration and early deployment of carbon capture and storage and new renewable technologies such as solar thermal.

4 ENVIRONMENTAL EFFECTIVENESS

4.1 Emission abatement

All the scenarios modelled lead, by design, to the same cumulative abatement of greenhouse gases by 2050. The trajectories, however, differ (see Figure 4-1). Even with a modest carbon tax, emissions are likely to only be stabilised rather than fall in the period to 2020 under the soft start scenario. By 2020, only 16 MT CO_2e of emissions from combustion of fuels in electricity generation have been abated, some 8% of current emissions from that sector. Emissions would be around 3% above today's levels. In the early action scenario, some 68 Mt are abated, or around 34% of current emissions from the electricity sector (see Figure 4-2). The main difference between the two scenarios is that the reduction in emissions under the soft start scenario is very sharp after 2020 (8% per annum between 2020 and 2030) and the level of emissions from 2020 is required to be lower than under the early action scenario in order to meet the cumulative target. This implies that delayed action would result in the burden of reducing emission would be faced by future generation, the efficacy of which will depend on whether this leads to lower overall costs.

Figure 4-1: Emissions of greenhouse gases, soft start versus early action



Complementary measures have very little impact on the trajectory of emissions in the early action scenario. Rather, the measures lead to differences in the mix of technologies required to meet annual abatement targets.

Complementary measures do have an impact on emissions under the soft start scenario, leading to a further reduction in emissions of some 20 Mt CO_2e by 2020 to around 185 Mt CO_2e. This occurs because of the assumption that a carbon price is applied (as opposed to a carbon target) before 2020 in the soft start scenario. In effect, there is no binding cap on emissions in the soft start scenarios until after 2020. Emissions would be around 7% below today's levels. However, even with this reduction, the overall level of emissions will still be higher than the early action scenario to the period to 2030. The other benefit of complementary is to reduce the costs of renewable generation and increase the uptake of this technology after 2020.

Figure 4-2: Abatement

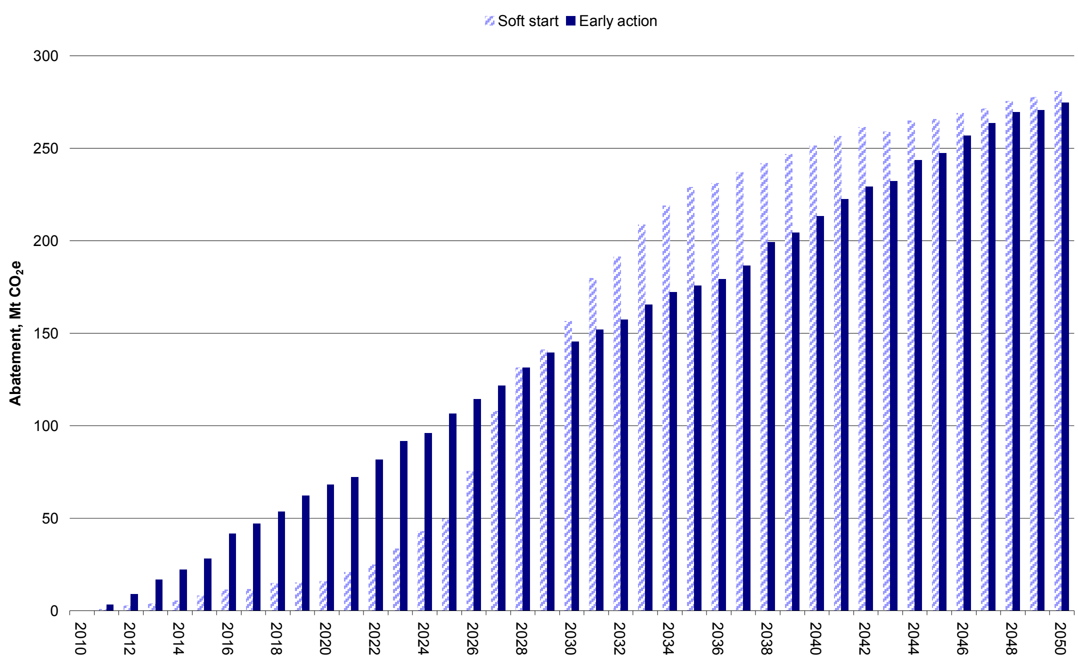


Figure 4-3: Impact on abatement of complementary measures, early action

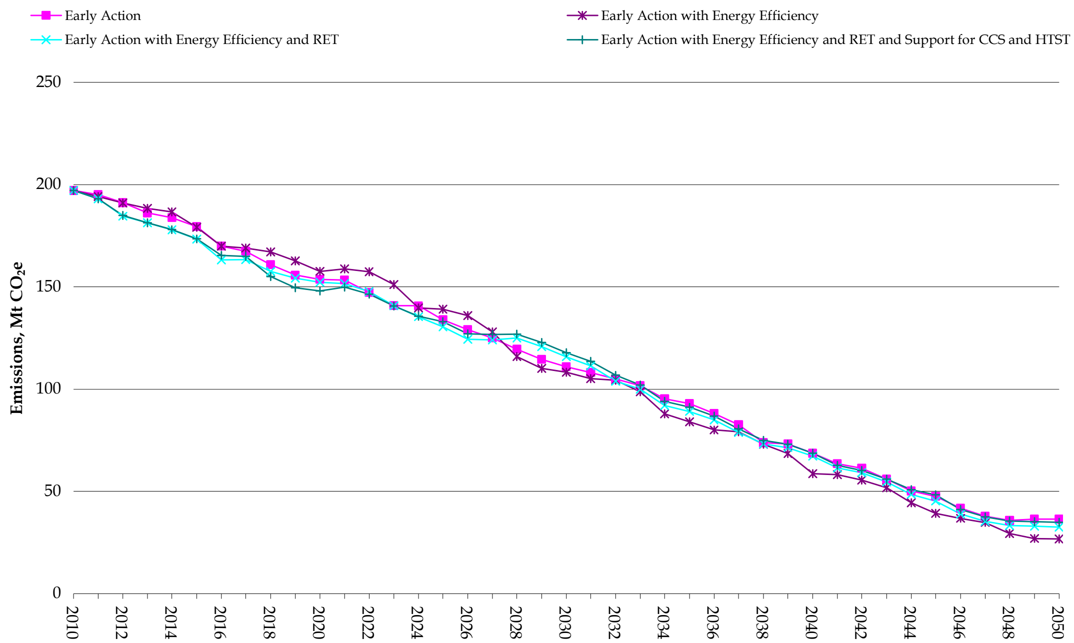
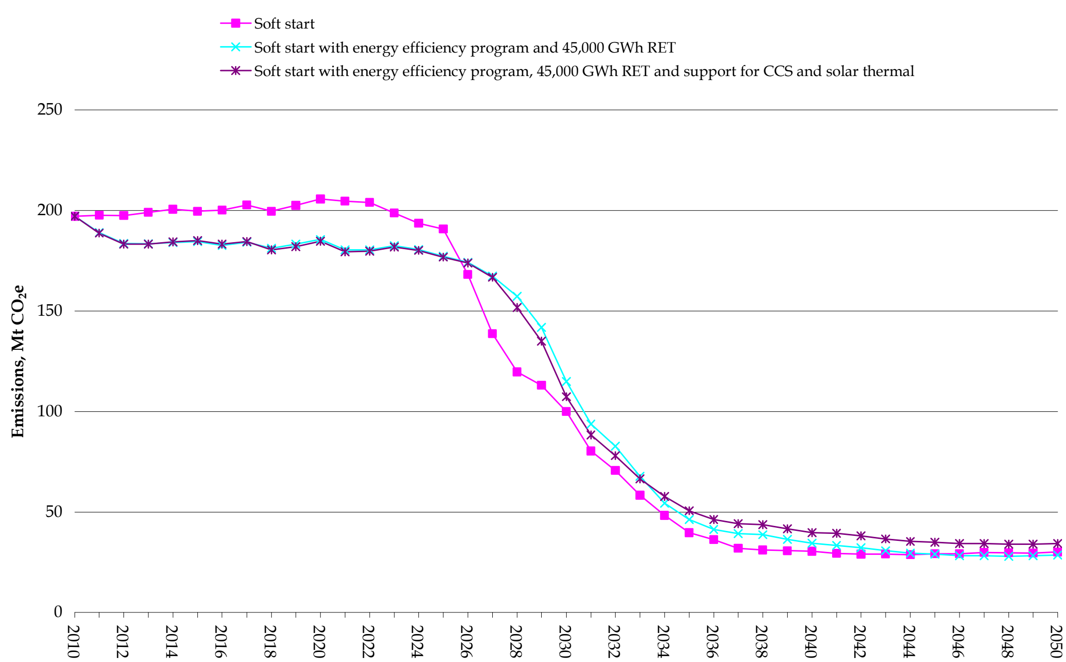


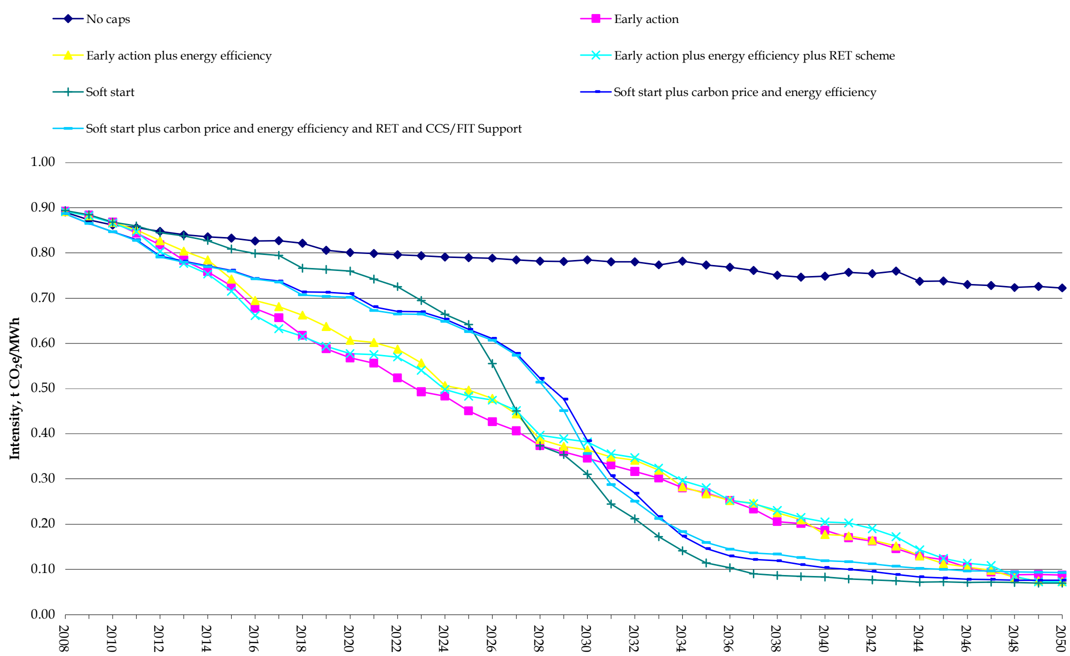
Figure 4-4: Impact on abatement of complementary measures, soft start



4.2 Emission intensity

Reflecting the emission trajectories, the emission intensities decline in all scenarios but at different rates. Even with no action, emission intensities decline due to further penetration of gas-fired generation and the greater proportion of generation from new, more efficient fossil fuel plant.

Figure 4-5: Emission intensity



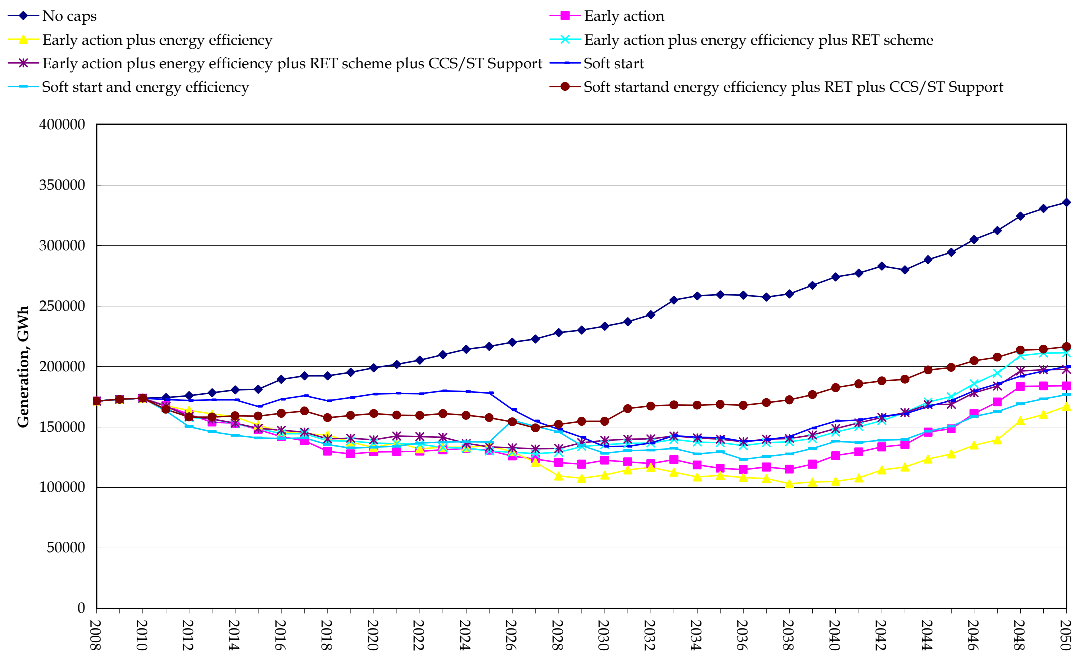
Under the early action scenario, the emission intensity drop more markedly in the period to 2030. More gas-fired and renewable energy generation is required, not only to meet load growth, but also to displace generation from existing fossil fuel plant.

Complementary measures generally do not change emission intensity greatly. On the one hand, additional renewable generation tends to reduce emission intensity. On the other hand, a greater level of renewable energy delays the need for reducing the level of generation from existing fossil fuel plant. With energy efficiency only, there is even the prospect that emission intensity is higher as the abatement is effectively done by reducing demand and this allows fossil fuel plant to continue operating at high levels.

4.2.1 Generation mix

Clearly, with such high levels of emissions, the mix of generation technologies changes over time. Coal-fired generation is likely to be lower than what would have occurred without any action, but the level of generation from this source does stabilise with the availability of carbon capture and storage. The initial decline is greater under the early action scenario but even here levels of coal fired generation bounce back as new low emission technologies are developed and deployed. As long as carbon capture and storage technology becomes fully developed and becomes competitive with other low emission technologies, levels of generation from coal could bounce back to recent historical levels. Across all scenarios, except where there is a dedicated deployment mechanism, carbon capture and storage technology is not deployed until after 2025. This illustrates that that if government wants to accelerate the deployment of low emission fossil fuels, additional measures above RD&D and emissions trading will be required.

Figure 4-6: Coal-fired generation, early action scenario



One of the major factors for the decline in coal-fired generation is energy efficiency. The proportion of coal fired generation in 2050 is the same as in the no action cases in many of the scenarios with energy efficiency, but the overall level of electricity demand is lower. The availability of nuclear generation could also reduces the level of coal-fired generation in the longer-term.

Renewable energy generation clearly expands under all scenarios, but more so in the early action scenarios and with complementary measures in place. Gas-fired generation also expands, but peters out from 2030 due to high gas prices and the higher cost of carbon capture and storage for this fuel.

Figure 4-7: Renewable energy generation

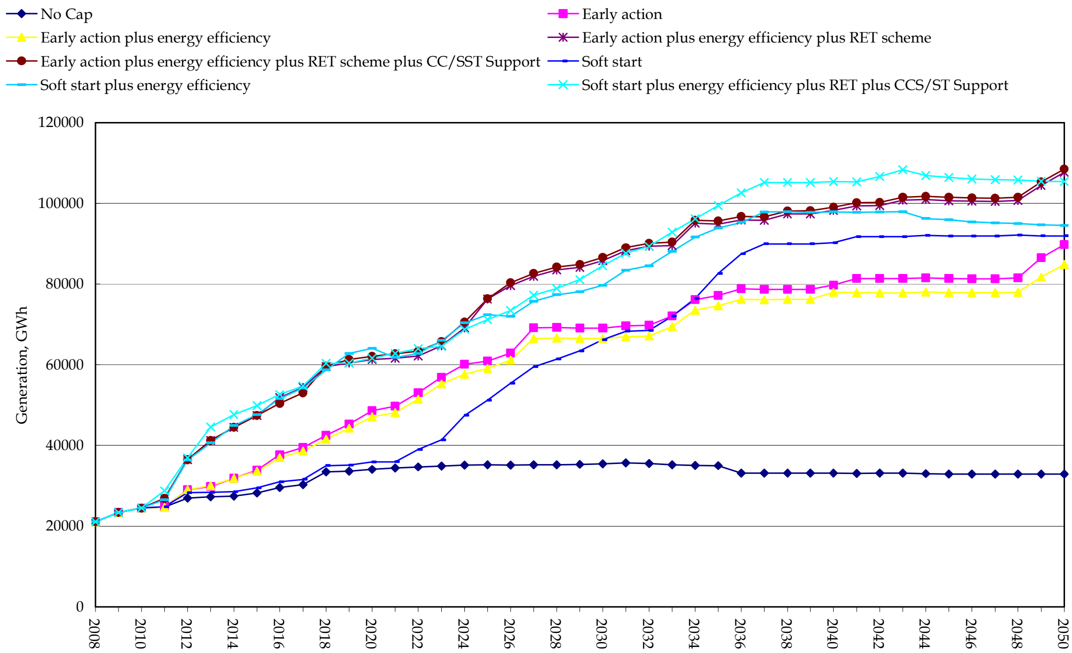


Figure 4-8: Gas-fired generation

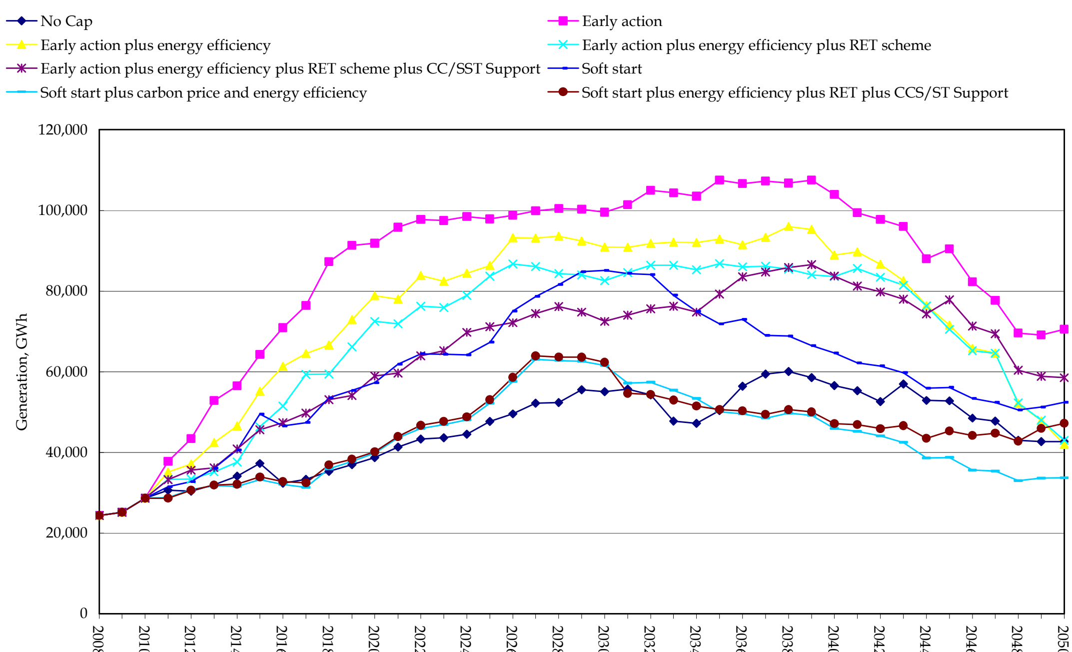
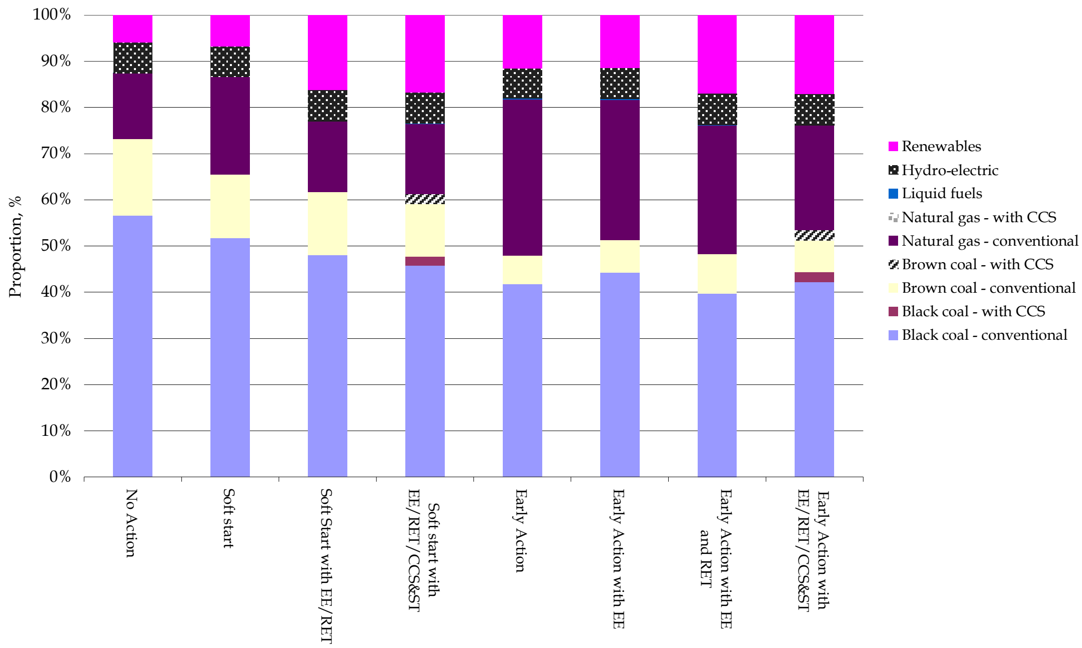


Figure 4-9: Share of generation, 2020



4.3 Factors affecting emissions and technology mix

A number of factors will affect the magnitude of the estimates of impacts obtained in this analysis.

First, the results depend crucially on the assumptions on trends on technology costs. Capital costs of generation technologies have increased in recent years due to increases in metal and raw material costs, shortage of engineers and constrained manufacturing capacity. In the analysis it is assumed that the current shortages dissipate over the next 5 years, after which capital costs resume their long-term declines in costs. Costs remaining high will not impact on the results obtained as long as the relative difference in costs between low emission and conventional technologies remain the same. However, it is possible that a world wide shift towards low emission technologies could exacerbate current shortages for these technologies especially in a world of deep cuts, so that the capital costs of these technologies remain high. On the other hand, for some small scale technologies (such as wind turbines and photovoltaic modules), early action to cut emissions or support renewable technologies could lead to large scale manufacturing plant being brought forward, helping to reduce costs sooner. The latter potential has also not been assumed in this modelling.

Assumptions of learning by doing potential are also uncertain. Rates employed in the analysis are based on recent historical estimates. However, there is some uncertainty over the potential technological development of some technologies such as wind turbines. For other technologies, cost reductions could accelerate due to economies of scale in manufacturing as demand for these technologies increase. Much of the cost reductions forecast for solar thermal technologies comes form estimate of increases in manufacturing scale.

The magnitude of the cost impacts also depend crucially on the availability of some new low emission technologies such as hot dry rock geothermal technology and carbon capture and storage technologies. Both of these technologies have yet to be demonstrated at large scale. There is uncertainty over whether the technologies will succeed at large scale and the timing of when the technologies will become commercialised. Delay in the development of either technology would mean reliance on higher cost low emission generation options.

An analysis was undertaken to determine the impacts if carbon capture and storage was not adopted. The analysis indicates that there would need to be reliance on new renewable technologies such as geothermal, high temperature solar thermal with storage, concentrating solar PV technologies and photovoltaic technologies. Further wind penetration was limited due to the assumption that wind generation capacity was limited to 25% of peak demand in any region. This limitation of wind generation could be overcome with development of energy storage options, but this is likely to be very expensive. Biomass options are limited by lack of low cost fuel resources and constraints on diversion of arable land to energy crops. The analysis indicates that wholesale prices would average about 40% higher and costs to the economy would nearly double.

Table 4-1: Impact of no carbon capture and storage technologies

Impact	Unit	With CCS (% generation)	Without CCS (% generation)
Wholesale price increases (average 2010 to 2050)	$/MWh	80	110
Technology Mix in 2050			
Conventional Coal	TWh	1 (0.03%)	1 (0.03%)
Coal with CCS	TWh	184 (51.5%)	0 (0%)
Conventional Gas	TWh	58 (16.2%)	58 (16.2%)
Gas with CCS	TWh	23 (6.4%)	0 (0%)
Total CCS	*TWh*	*207 (58.0%)*	*0 (0%)*
Wind	TWh	15 (4.2%)	39 (10.9%)
Biomass	TWh	33 (9.2%)	40 (11.2%)
Geothermal	TWh	15 (4.2%)	48 (13.4%)
Solar/PV	TWh	11 (3.1%)	155 (43.4%)
Hydro	TWh	17 (4.8%)	17 (4.8%)
Total Renewable	*TWH*	*91 (25.5%)*	*299 (83.5%)*
Resource Costs	$M	32,875	60,423

Note: Based on the early action scenario with energy efficiency, a 45,000 RET and no nuclear energy. Resource costs calculated using a 4% discount rate. Wholesale price is time weighted average for Australia.

The inclusion of nuclear power does not significantly impact the growth of renewable energy in the scenarios, but it does have a significant impact on fossil fuel generation. For example, where nuclear power stations are included, coal generation decreases by around 30% in 2050 from where it would have been otherwise.

Due to the time it would take to establish a domestic nuclear power industry in Australia, a decision to allow nuclear generation would make only a modest contribution to meeting energy demand with nuclear reactors supplying around 10% of total generation to 2050.

Other limitations of the modelling included:

- Demand reductions under emissions trading were not modelled, apart from that occurring through an energy efficiency program. It would be expected that demand would fall in response to higher prices as demand switched to less energy intensive activities and products.
- Gas price forecasts are assumed to remain the same in all scenarios. Gas fuel usage does not increase in substantial amounts as although gas-fired generation increases, there is a switch towards more fuel efficient combined cycle generation.
- Additional transmission costs are only partially captured in the form of costs of expanded interregional networks and connection costs for generators. Costs of upgrading the meshed networks within each state (that is the shared network which is used to transmit electricity from a range of generation sources) were not modelled. This is likely to be of equal importance to new renewable and fossil fuel generation.

5 COST EFFECTIVENESS

5.1 Productivity costs

Productivity costs represent the additional costs in electricity generation and in processing of fossil fuels in order to meet abatement targets. In this study, it is estimated by measuring the changes in capital, fuel and operating costs in electricity generation and fuel extraction, processing and transport.

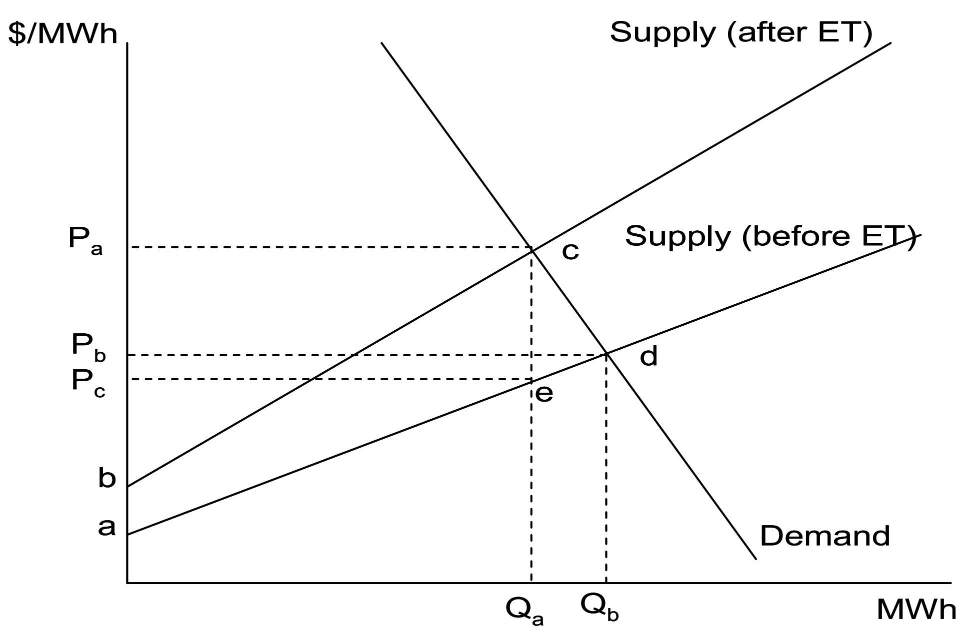
The process for calculating social costs is shown in Exhibit 5-1. Effectively the social cost is calculated from the additional costs incurred in electricity generation as a result of meeting specific emission targets. It should be noted that to provide a more accurate picture of the outcomes of emissions trading, the social cost should be compared to the benefits to society derived from reduced emissions. The benefits of avoided emissions are not calculated as part of this exercise.

Exhibit 5-1: Social cost of emissions trading

The cost to the Australian community of expending resources to reduce emissions is estimated from changes to the costs of generation.

The social cost is illustrated in the following chart. The demand for electricity as a function of electricity price is shown by the curve entitled "Demand". Before emissions trading, the marginal cost of supply is shown as "Supply (Before ET)". Imposition of emissions trading increases the marginal cost of electricity supply for every unit of output (the curve "Supply after ET"). Prices increase from P_b to P_a and the quantity of electricity demanded goes down from Q_b to Q_a.

The social cost is the additional cost that is expended on resources to produce the same amount of electricity as before. The additional resources cannot be used in other useful economic activities. In the chart, this is represented by the area of *abcd*.



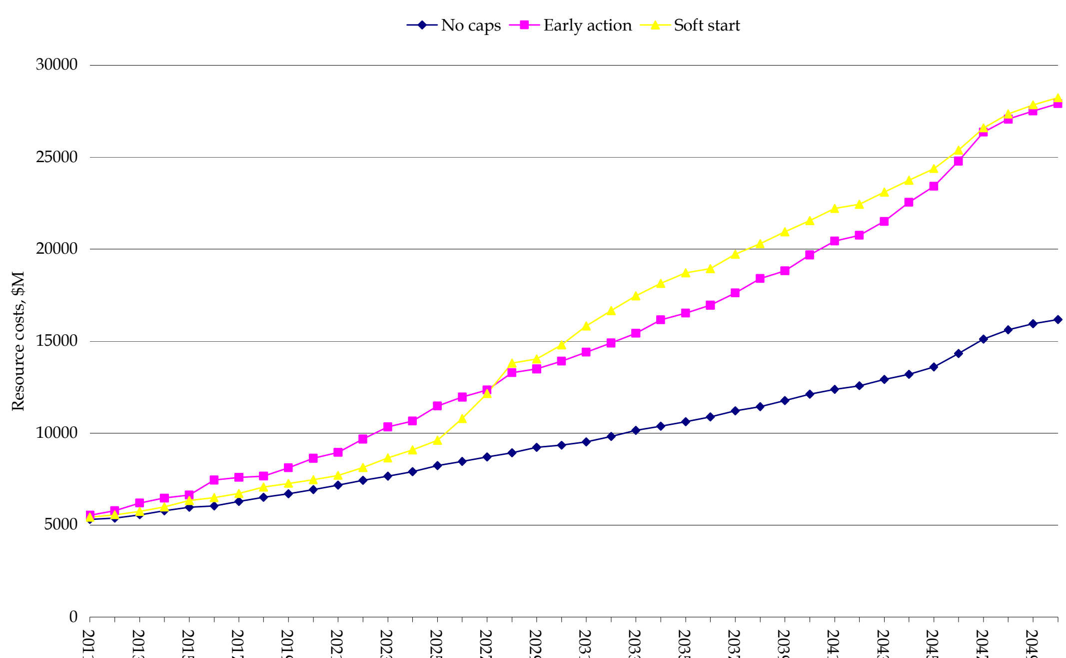
Estimation of the social cost for electricity generation is undertaken as follows:

- From the reference or base case scenario we calculate the total cost of generation (capital, fuel and operating costs). This is the area OP_bdQ_b in the chart.
- From the relevant emissions trading scenario, we calculate the total cost of generation (capital, fuel and operating costs). This is the area OP_adQ_a in the chart.
- Undertake another simulation with no emissions trading but the same demand reduction as occurs under emissions trading. Calculate the generation costs under this simulation to get the area OP_ceQ_a in the chart. Subtract OP_ceQ_a from OP_adQ_a to get the area *abce*.
- The area *ecd* is calculated as half of the price difference (Pa – Pc) and quantity difference (Qa – Qb), assuming linear demand and supply curves.
- The social costs are then the sum of values of *abce* and *ecd*.

5.2 Costs of delaying action

Differences in capital, fuel and operating costs for the soft start and early action scenarios are shown in Figure 5-1. Because of the introduction of emission trading, resource costs are higher in both scenarios compared with a no action scenario. Resource costs are significantly higher in the period to 2027 for early action. However, resource costs for the delayed action are significantly higher than for the early action case over the long-term reflecting the need to bring in significant low emission capacity to meet more stringent targets.

Figure 5-1: Annual resource costs, soft start versus early action



On a present value basis, the amount of additional resource costs is similar over the study period from 2010 to 2050. There is no consensus among economists around what discount rate is appropriate in climate change policy studies. Which scenario has the higher cost depends on the discount rate to be used. With discount rates higher than 5%, the soft start case has a slightly lower cost (around $1.6 billion for a 6% discount rate and $2.5 billion for a 9% discount rate). Discount rates less than 5% lead to lower cost for the early action case (around $7 billion for a 1% discount rate).

The additional resource cost in both cases represent less than 0.30% of the present value of Gross Domestic Product from 2010 to 2050, assuming a 1% discount rate, to less than 0.15% of the present value of GDP when using a discount rate of 9%.

The difference in economic costs depends in part on two factors. First, the degree of lock in of high emission technologies affects resource costs. Delaying action could lead to lock in of new high emission plant in the period to 2020, requiring a higher permit prices and more expensive low emission generation later on to achieve the same level of abatement[12]. In this study, the level of lock in is reduced by the carbon price imposed in the period from 2010 to 2020 ($15/t CO_2e to $35/t CO_2e). This is sufficient to alter the mix of new plant towards low emission technologies, allowing for example for a preference for gas-fired CCGT rather than conventional coal-fired technology for new base load plant in most eastern states, but not enough to encourage large scale deployment of renewable energy. Second, early action could accelerate the rate of cost reduction through learning by doing, reducing the long-term cost of abatement.

5.3 Impact of complementary measures

Complementary measures can reduce the economic costs of an emission trading scheme, as can be seen for the early action scenario in Figure 5-2. Several characteristics were observed in the analysis:

- Energy efficiency led to a substantial reduction in economic costs, and was by far the biggest source of reduction in the economic cost impact of emission trading. This influence relies on their being sufficient energy efficiency options with net benefit to the energy users and/or energy prices increases driving this level of demand reduction.

- A technology deployment measure can lead to further reductions in economic costs in the long-term, but this is contingent in their being the potential for learning by doing from greater adoption of renewable energy resources and other low emission technologies in Australia. The saving in resource costs from a renewable energy target in the early action scenario is limited by the fact that high levels of renewable energy generation are required before 2020 even without a renewable energy target to meet

[12] In an earlier report for this study, it was found that delaying action led to higher costs than early action. This was because in this case, the soft start involved a carbon price of only $10/t for the period from 2010 to 2020. This level of permit price is insufficient to cause a switch from coal to gas fired generation for new plant. In the current study, the carbon price is high enough for the switch to occur, minimisng the lock in of high emission plant.

the emission reduction targets. Thus the contribution of a renewable energy target is greater in the soft start scenario.

- Similarly support to demonstrate and commercialise carbon capture and storage costs can lead to lower economic costs in the longer term. This result depends in part of learning by doing in Australia. Nor does it account for the possible crowding out of other economic activity as funds are diverted in research and demonstration of these technologies.

Figure 5-2: Complementary measures and resource costs

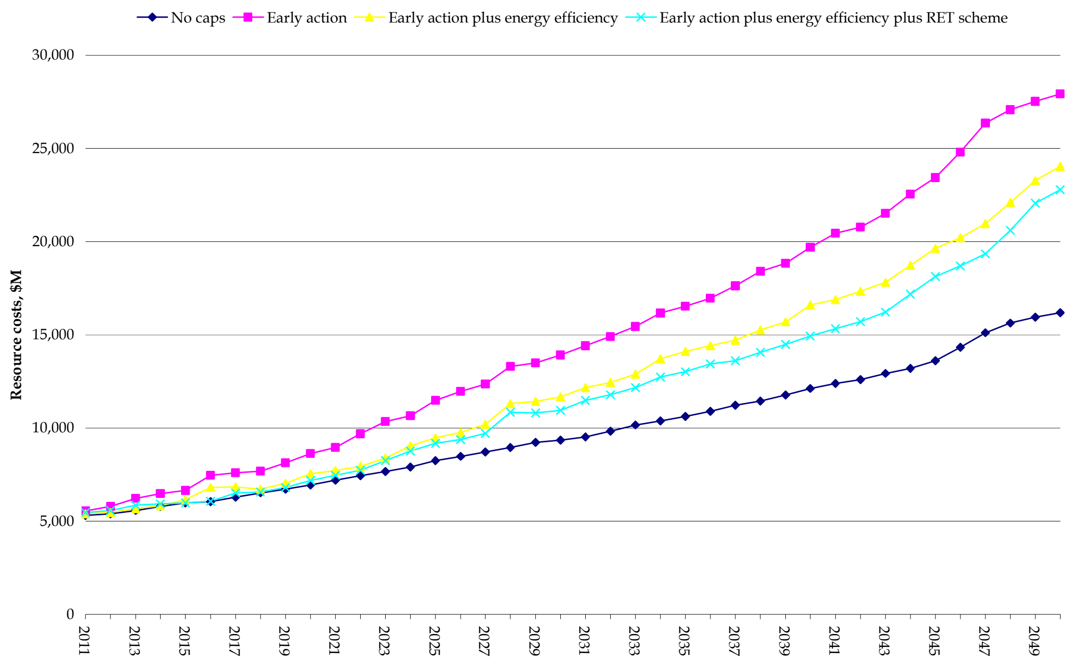
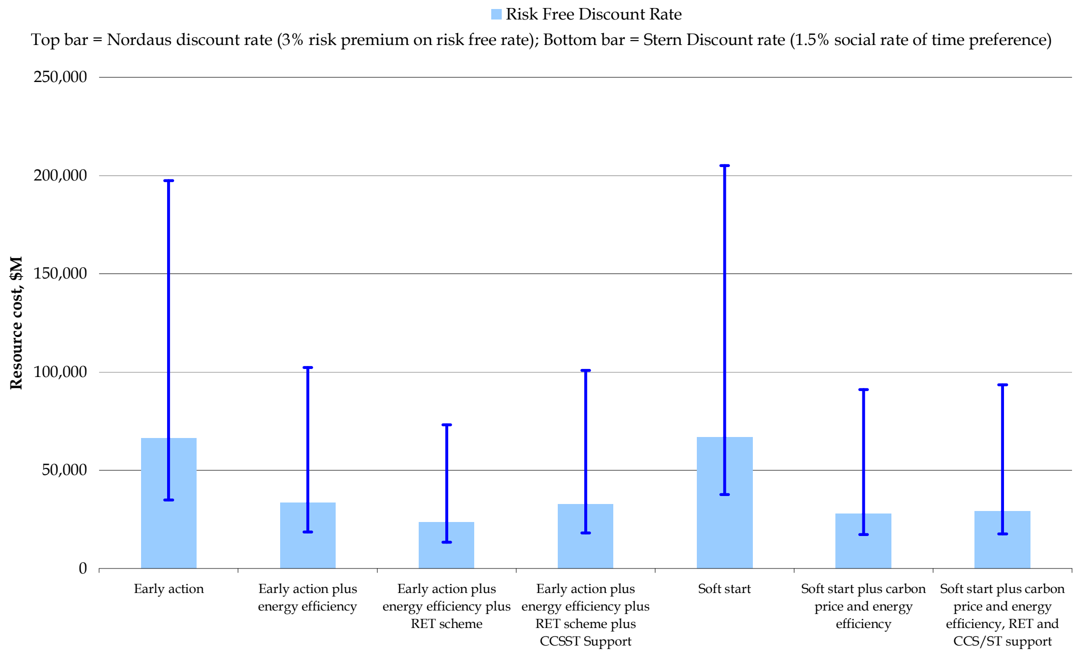


Figure 5-3: Difference in resource costs



Note: Difference in resource costs is calculated as the difference in the present value of resource costs from the no action scenario, over the period 2010 to 2050 using the discount rate nominated.

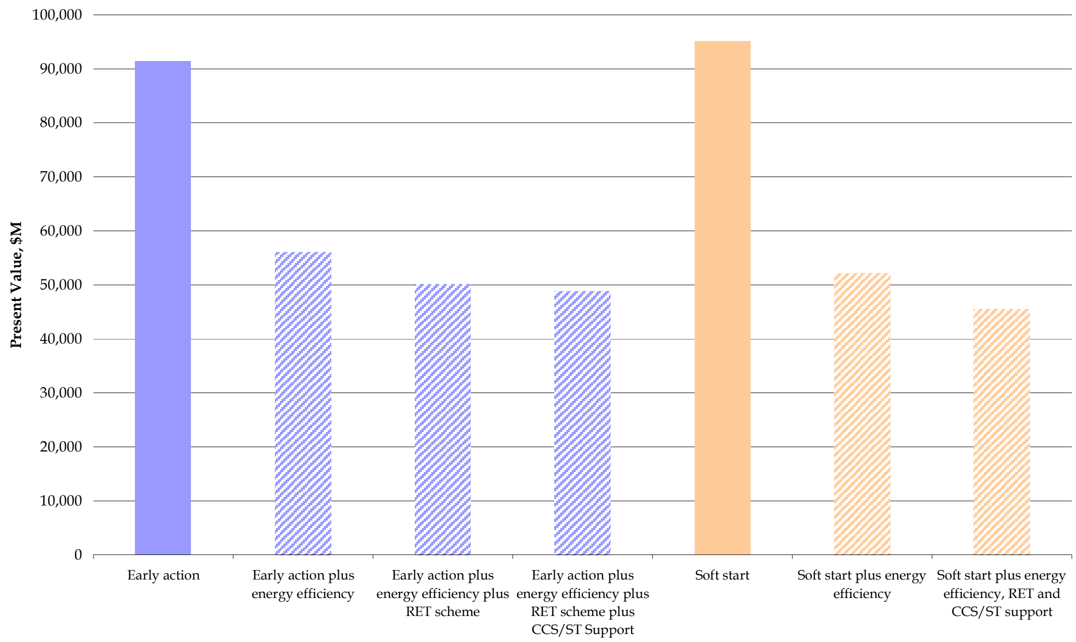
Another approach is to use a discount rate that declines with time, which is justified if there is some uncertainty over the future return to capital, future growth rates, intra-generational distribution and observed individual choices of discount rates.[13] The present value of resource costs have been recalculated using the following assumptions on the declining discount rate:

- 7% for the period to 2008 to 2018;
- 4% for the period 2018 to 2038; and
- 2% for the period beyond 2038.

The estimates, shown in Figure 5-4, indicate there is little difference in the economic costs of alternative timing for deep cuts in emissions. Complementary measures, provided these measures are targeted and well designed, are likely to reduce the long-term cost of emissions trading, with this benefit being greater if the commitment to deep cuts in emissions is delayed.

[13] IPCC (2007), *Climate Change 2007 – Mitigation of Climate Change*, contribution of Working Group III to the Fourth Assessment Report of the IPCC.

Figure 5-4: Present value of resource costs of measures with discount rates declining over time



6 DISTRIBUTIONAL IMPACTS

Under an emissions trading scheme, electricity generators incur additional costs as they are required to purchase permits to emit greenhouse gases. Generators attempt to pass on the cost through the wholesale market, which results in changes to energy prices.

6.1 Permit prices

Permit prices are shown in Figure 6-1. The permit price path depends on the timing of caps and the level of caps imposed. Note that these permit prices do not represent national carbon prices. They only represent the carbon prices required to achieve the emission reductions in the electricity sector.

The soft start scenarios have similar permit price trajectories with initial permit prices low and steadily increasing to \$35/t CO_2e by 2020. Thereafter, prices rise gradually to reach around \$95/t CO_2e in 2050. Enabling energy efficiency reduces the permit price rise, but the sharp cuts needed still require expensive low emission options to be adopted.

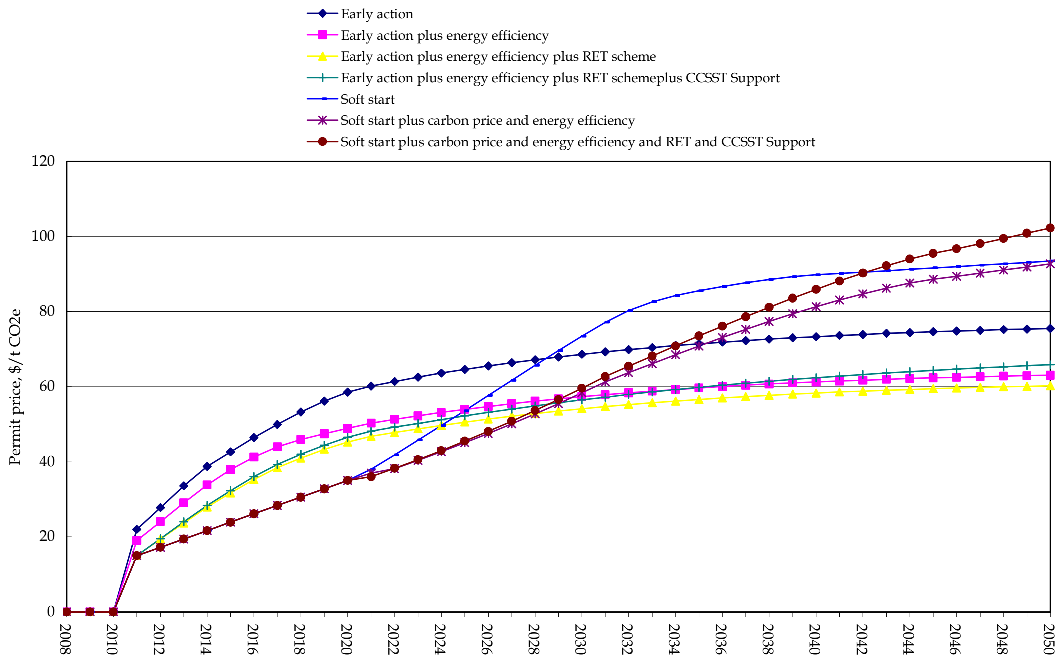
The increase in permit prices slows from 2030 because the permit price in the long-term is governed by the marginal cost of low emission technologies which are required to be deployed to achieve the emission targets. After 2025 CCS begins to be deployed, that subsequently slows permit prices for abatement in electricity generation.

Permit prices for the early action scenario are higher than for the soft start scenarios until about 2025. This follows from the earlier cuts in emissions required under this scenario. Prices increase to around \$60/t CO_2e by 2020. This level is required to bring on sufficient renewable energy generation early enough to meet the target.

However, prices level out from 2025, reaching around \$75/t CO_2e in 2050. In the longer term prices are lower than the soft start scenarios as the emission caps are higher in the early action scenario. Further, higher permit prices are required in the soft start scenario to reduce the level of emissions from new fossil fuel plant brought on before 2020.

An energy efficiency program reduces the permit price required to achieve a given abatement target. Doubling the historical rate of energy efficiency leads to permit prices around \$10/t CO_2e lower than without an energy efficiency scheme. However, other complementary measure lead to modest reduction in permit prices due to the high levels of low emission technologies required even without these complementary measures. Any reduction is caused by a learning by doing effect.

Figure 6-1: Permit prices



6.2 Electricity prices

Wholesale electricity prices are higher as a result of emissions trading, with the time weighted average prices following the relationship of the permit price (see Figure 6-2).

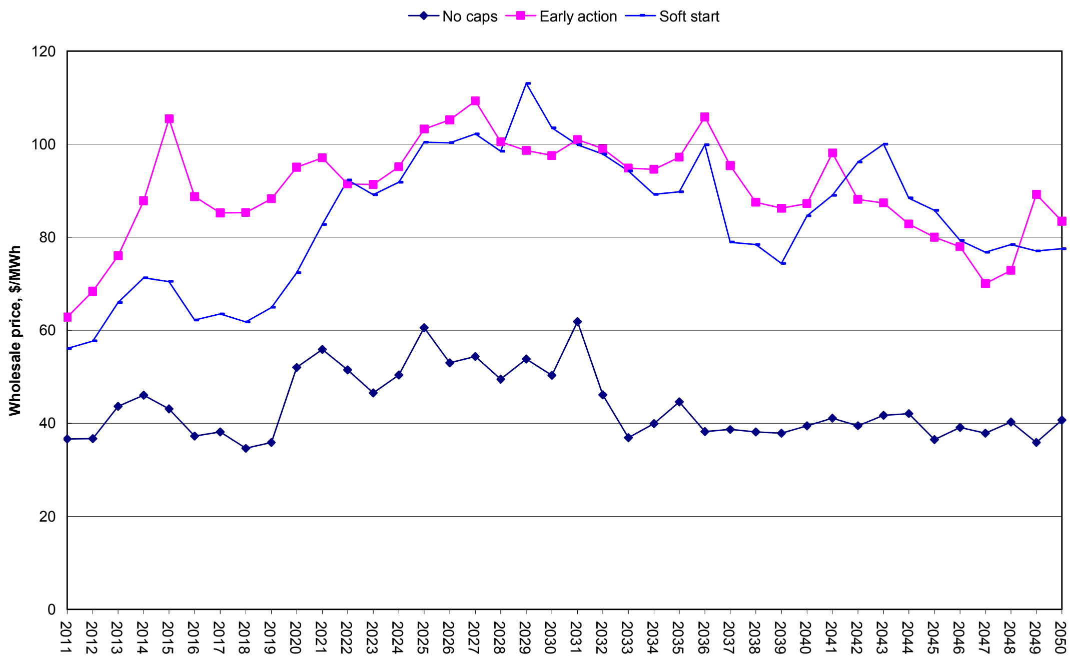
For all scenarios the NEM price increase grows steadily in the period to 2020, relative to the no action case. The price separation between the soft start and early action is not as great as the increase in permit price largely due to the increase in renewable generation in each scenario, which suppresses the price increase as a result of the low short run marginal cost of renewable generation and because more new generation capacity is deployed than is required to meet load growth alone.

Prices tend to converge, roughly, regardless of the emissions target, after 2020. This is partly an artefact of the averaging procedures used to get average prices, which tend to smooth out variation in price increases amongst the States. It is also due to the fact that the higher the target the more low emission plant are deployed, whose marginal costs do not increase greatly even as permit prices increase. These low emission plants replace existing coal units, with many of these retired earlier or retrofitted with CCS technology. This is particularly true in the high permit case of scenario three which sees either the retirement or retrofit of all coal-fired plants. Subsequently the wholesale electricity price decreases during this period, converging with that of the other scenarios.

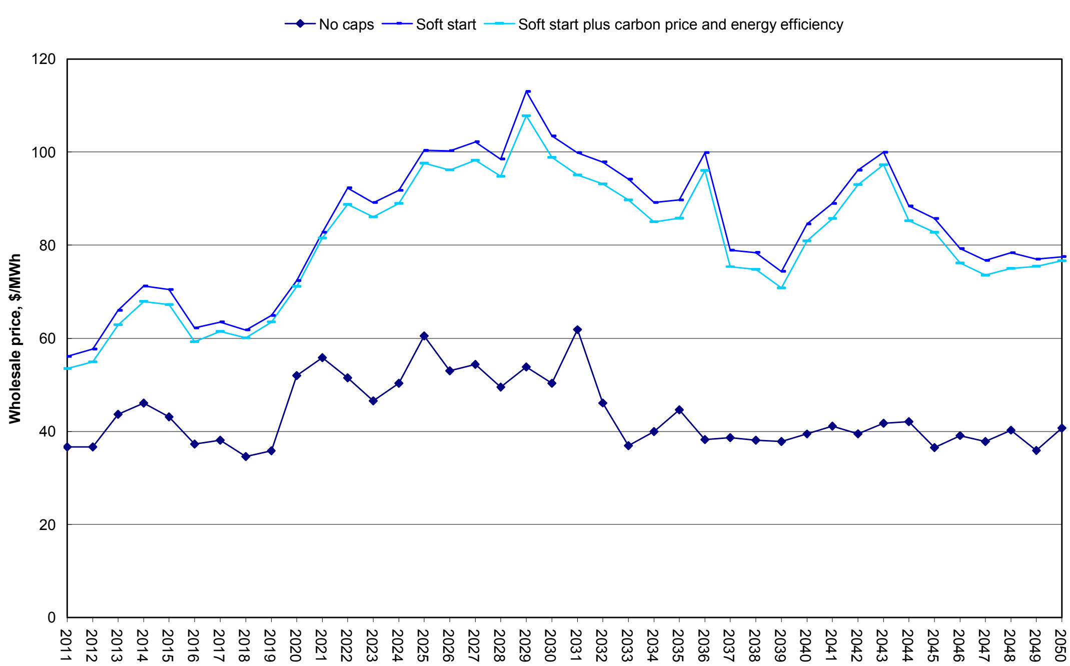
Wholesale prices in the SWIS and DKIS display the same relationship to those of the NEM, with prices increasing in line with the permit price.

Figure 6-2: Wholesale electricity prices (time weighted average)

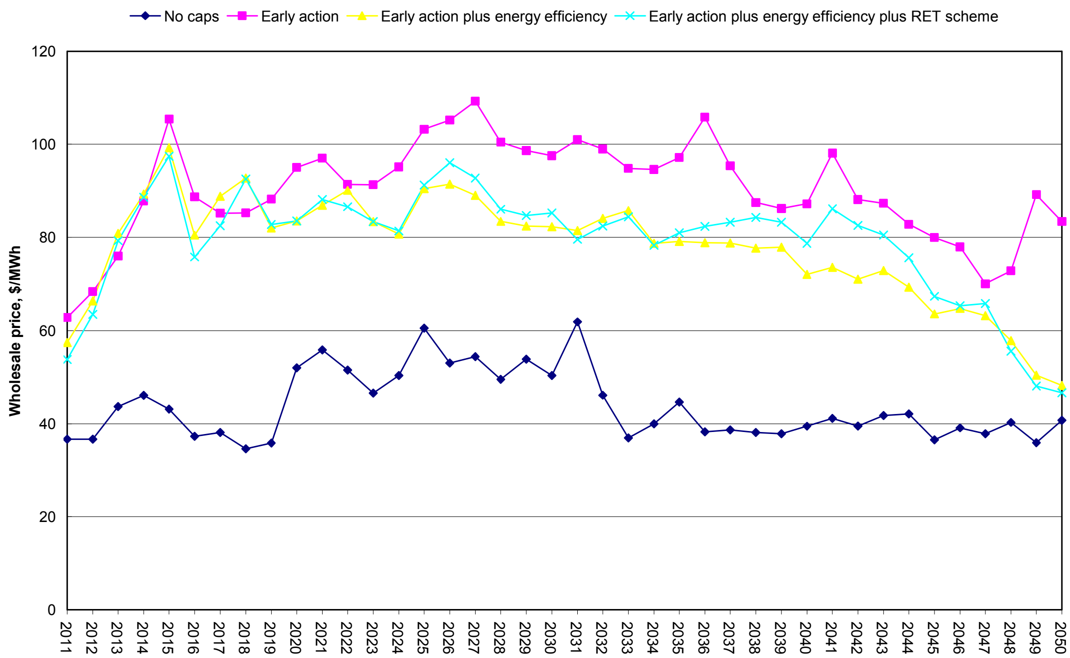
(a) Soft start versus early action



(b) Complementary measures – soft start



(c) Complementary measures – early action



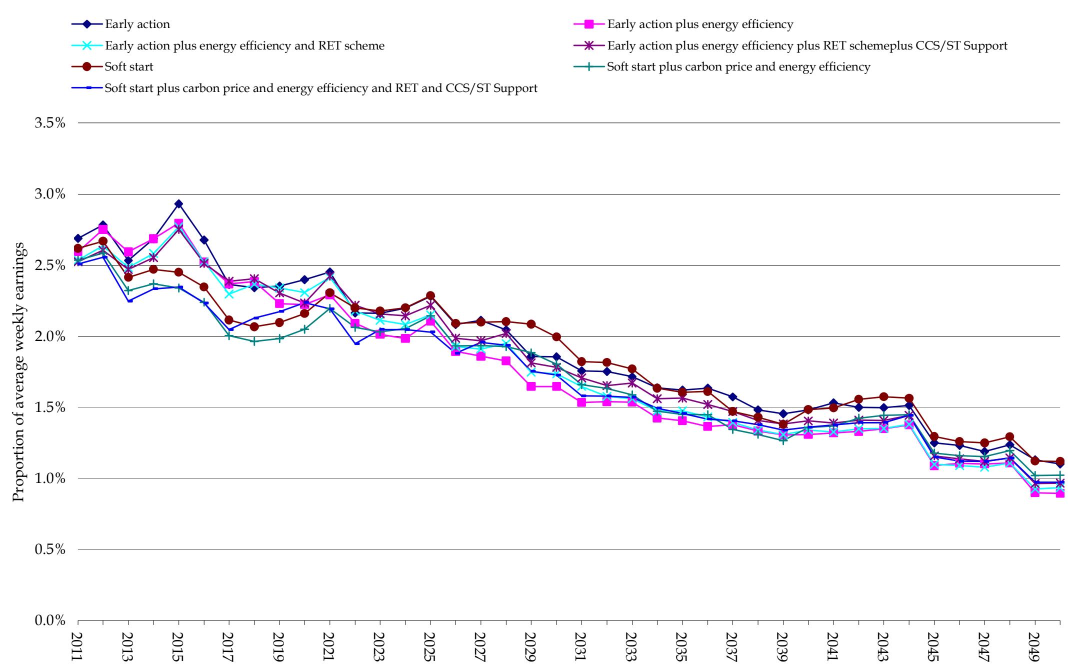
Prices increases in absolute terms are similar across most states. However, in proportional terms, the highest price increases are observed in New South Wales and Victoria. This is because in these states high emitting and conventional fossil fuel generation operates much of the time, and sets the relatively lower wholesale price in the base case. These states also have large resources of renewable energy in the base case which also depresses the base wholesale price. Price increases in Tasmania in absolute terms tend to be lower than the price increase in Victoria on a time weighted basis due to the lower demand for electricity which delays the time that prices converge to the cost of new gas-fired generation in Tasmania. Western Australia and Northern Territory have relatively lower percentage increase in prices due to the higher base price and, in the case of Northern Territory, the lower emission intensity of the predominantly gas-fired plant operating in the system.

Retail price increase observes the same patterns as for wholesale prices (see Table 6-1). Retail prices are around 30% to 40% higher for the soft start scenarios compared with 50% to 67% for the early action scenarios in the period to 2020. Price increases are comparable across all scenarios from 2020 onwards. The higher retail prices translates into higher household expenditure on electricity of between $3.00/week to $5.00/week higher in the period to 2020 and $6.00/week to $9.00/week higher in the period after 2020. However, this is still less than the growth rate in incomes projected for the same period. Expenditure on electricity is still expected to fall as a proportion of household income even with the higher energy prices under the most stringent caps.

Table 6-1: Retail price increases

	2010-2020	2021-2030	2031-2040	2041-2050
Early action	67%	68%	75%	55%
Early action plus energy efficiency	64%	57%	57%	39%
Early action plus energy efficiency plus RET scheme	58%	57%	59%	36%
Early action plus energy efficiency plus RET scheme plus CCS/ST Support	50%	53%	57%	34%
Soft start	40%	72%	76%	62%
Soft start plus carbon price and energy efficiency	37%	67%	70%	58%
Soft start plus carbon price and energy efficiency and RET plus CCS/ST Support	31%	50%	61%	41%

Figure 6-3: Additional expenditure on energy as a proportion of average weekly earnings



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 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 electrical supply regions. MMA partitions the SWIS into three zones (south west, goldfields and north west 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.

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

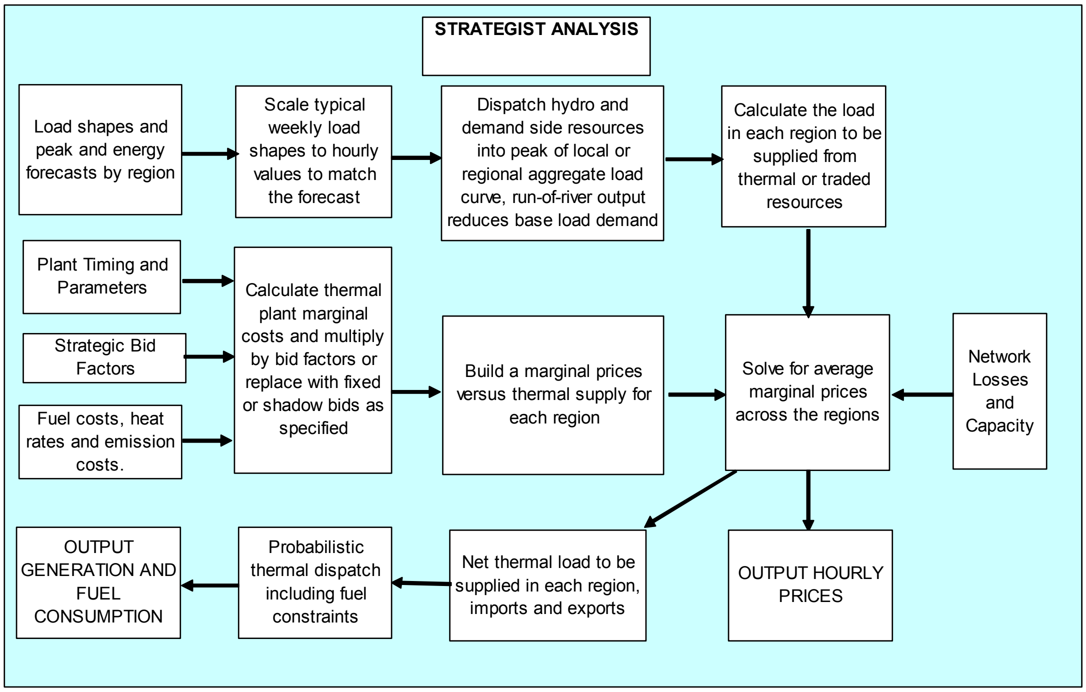
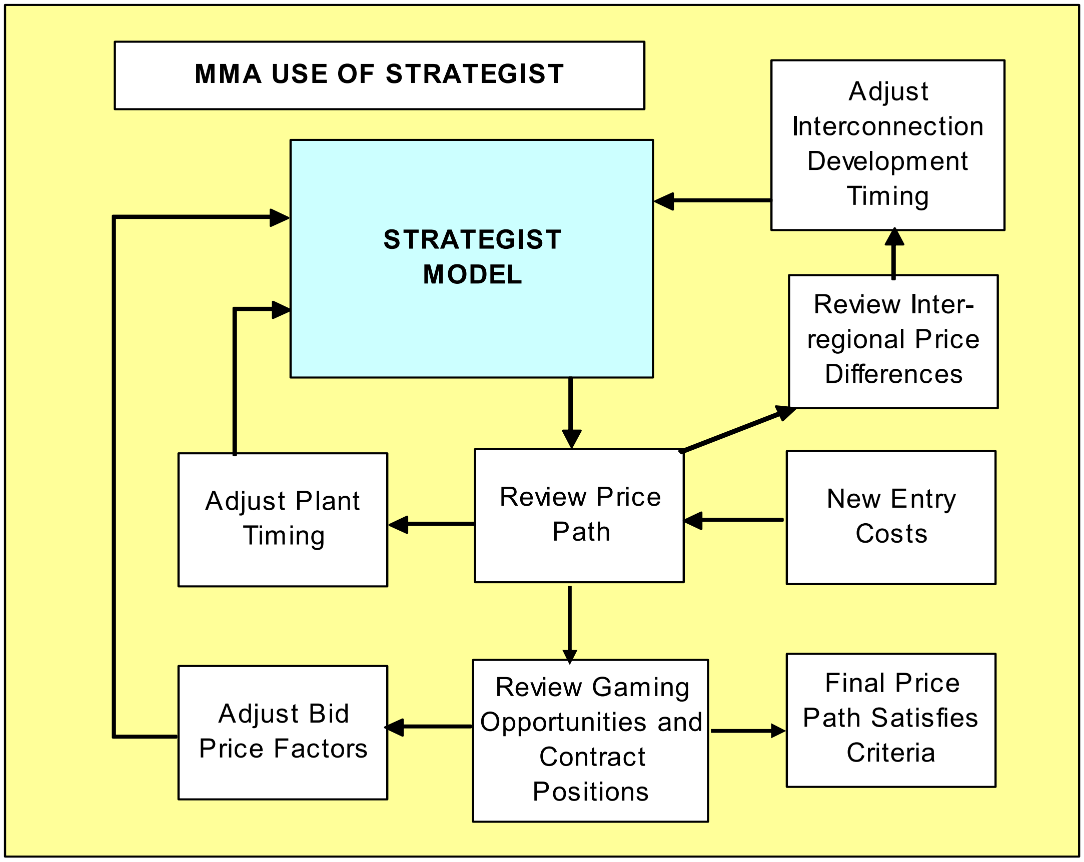


Figure A-2: MMA Strategist modelling procedures



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[14], having regard to all possible thermal plant failure states and their probabilities. The prices are solved across the regions of the SWIS 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.

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.

[14] In MMA's model of the SWIS, we assume three regional nodes to reflect major transmission constraints (South West Region, with a regional reference node at Muja, Goldfileds Region and North County region).

APPENDIX B ELECTRICITY MARKET MODEL ASSUMPTIONS

B.1 Base 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 and other scenarios include:

- The Queensland Cleaner Energy Policy continues until 2020. In the reference 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.
- 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.
- The generator bidding profiles reflect generator contracting levels and assumed revenue targets, based on MMA's benchmark study for 2004 calendar year.
- The retirement of Swanbank B units in 2011.
- A 170 MW VIC->SA upgrade on the Heywood interconnector in July 2009 to augment supply to South Australia.

B.1.1 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
- Other generators continue under existing portfolio groupings.

B.1.2 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 B-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 B-1: Indicative Average Variable Costs for Thermal Plant ($June 2007)

Technology	Variable Cost $/MWh	Technology	Variable Cost $/MWh
Brown Coal – Victoria	$7 - $11	Brown Coal – SA	$20 - $25
Gas – Victoria	$39 - $54	Black Coal – NSW	$18 - $22
Gas – SA	$39 - $90	Black Coal - Qld	$14 - $20
Oil – SA	$175 - $220	Gas - Queensland	$25 - $57
Gas Peak – SA	$80 - $115	Oil – Queensland	$200

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 rife. With gaming, the outcome is not likely to be greatly different from our current results.

B.1.3 *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%.

Table B-2: Costs and Performance of Thermal Plants

Plant	No Units	Sent Out Capacity	Available Capacity factor	Full Load Heat Rate	Variable O&M	Variable Fuel Cost $/GJ (2007)
Tasmania						
Bell Bay	2	226.9	92.41%	10.9	$2.39	$3.80
New GT	0	0.0	92.03%	11.5	$3.45	$5.20
Victoria						
Loy Yang A	4	1899.0	92.85%	13.0	$0.96	$0.45
Loy Yang B	2	920.0	92.49%	12.8	$0.96	$0.45
Yallourn W	4	1368.0	88.53%	13.6	$1.19	$0.47
Hazelwood	8	1472.0	90.45%	14.8	$2.39	$0.60
Anglesea	1	143.5	94.37%	15.1	$1.19	$0.15

Plant	No Units	Sent Out Capacity	Available Capacity factor	Full Load Heat Rate	Variable O&M	Variable Fuel Cost $/GJ (2007)
Energy Brix	3	136.2	86.58%	15.4	$2.39	$0.75
Newport(1)	1	484.5	92.97%	10.3	$2.39	$3.80
Jeeralang A	4	230.8	94.96%	13.7	$7.16	$3.50
Jeeralang B	3	253.7	94.96%	12.8	$7.16	$3.30
Bairnsdale	2	89.6	93.23%	11.5	$3.58	$3.86
Valley Power (EME)	6	334.3	94.96%	13.7	$7.16	$3.30
AGL Somerton	4	151.2	87.51%	13.5	$2.39	$3.50
Laverton North	2	310.4	93.95%	11.6	$3.58	$4.50
South Australia						
Northern	2	494.9	93.56%	11.4	$2.32	$1.29
Playford B	4	222.0	83.66%	15.0	$3.48	$1.29
Torrens Island A	4	478.8	87.51%	10.8	$7.16	$5.22
Torrens Island B	4	782.8	87.51%	10.5	$1.79	$3.75
Pelican Point	1	462.6	93.23%	7.7	$2.39	$3.42
Mintaro 1	1	85.6	89.01%	16.0	$7.16	$7.54
Dry Creek	3	139.3	89.01%	14.0	$7.16	$7.54
Ladbroke Grove	2	83.6	92.03%	10.1	$5.97	$3.70
Osborne	1	187.4	93.95%	10.7	$2.32	$3.67
Snuggery	3	62.7	87.91%	15.0	$7.16	$14.11
Port Lincoln	2	46.8	91.33%	12.1	$7.16	$14.11
Quarantine	4	91.5	89.01%	10.4	$7.48	$3.67
Hallett	8	191.0	89.11%	19.4	$8.18	$3.67
Angaston	24	39.8	94.15%	9.0	$10.25	$7.54
New South Wales						
Bayswater	4	2592.7	94.69%	10.1	$2.39	$1.42
Eraring	4	2481.6	92.79%	9.8	$2.39	$1.68
Mt Piper	2	1240.8	91.33%	10.0	$2.27	$1.50
Vales Point	2	1240.8	88.53%	10.1	$2.99	$1.72
Wallerawang	2	940.0	86.61%	10.7	$3.58	$1.42
Liddell	4	1955.2	93.79%	11.2	$2.16	$1.42
Munmorah	2	576.0	83.21%	11.2	$2.37	$1.55
Smithfield	1	170.0	92.33%	10.0	$4.54	$3.96
Hunter Valley GTs	2	50.7	88.81%	23.4	$8.24	$14.11
Tullawarra	1	400.0	94.15%	7.4	$3.00	$3.70
Pt Kembla (New)	1	193.9	92.03%	7.1	$3.00	$0.50
Munmorah GT	4	149.5	92.19%	11.1	$2.00	$3.70
Queensland						
Barcaldine CC	1	50.0	91.33%	8.0	$3.58	$3.72
Callide B	2	658.0	86.80%	9.9	$1.72	$1.39
Callide C	2	864.8	90.73%	9.0	$1.19	$1.40
Collinsville	5	174.8	89.43%	13.7	$2.39	$1.71

Plant	No Units	Sent Out Capacity	Available Capacity factor	Full Load Heat Rate	Variable O&M	Variable Fuel Cost $/GJ (2007)
Gladstone	6	1579.2	91.19%	10.2	$1.04	$1.62
Stanwell	4	1353.6	92.35%	9.9	$0.96	$1.43
Tarong	4	1316.0	92.35%	10.0	$0.99	$1.09
Tarong North	1	416.4	91.33%	9.0	$0.99	$1.20
Swanbank B	4	467.5	79.65%	10.7	$2.39	$1.53
Swanbank E	1	373.5	94.15%	8.1	$2.39	$3.42
Roma (Boral)	2	67.7	87.51%	13.5	$4.78	$3.72
Mackay GT	1	32.8	94.25%	13.5	$9.55	$14.11
Yabulu CCGT	1	230.9	94.25%	11.4	$2.39	$3.16
Mt Stuart GT	2	292.5	94.25%	13.8	$4.78	$14.11
Oakey GT	2	318.4	94.25%	11.5	$4.78	$4.65
Millmerran	3	1185.4	91.33%	9.9	$1.07	$0.66
Braemar	3	477.6	94.15%	11.1	$4.78	$3.52
Kogan Creek	1	717.2	91.33%	10.2	$1.07	$0.66

Sources: Historical data published by NEMMCO, and in annual reports of the generators.

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 AGO.

B.1.4 Plant Upgrading

Loy Yang Power has announced its intention to increase the capacity of Loy Yang A up to 2,200MW with some units rated at 580 MW. Snowy Hydro has indicated that it intends to replace the turbine runners at Murray 2 and Tumut 3. As a result, Murray 2 plant capacity will increase from 550 MW to 620 MW and Tumut 3 plant capacity will increase from 1,500 MW to 1,650 MW by the end of the decade.

Delta electricity has publicly announced plans to upgrade the Mt Piper units, increasing total plant capacity from 1320 MW to 1500 MW. Similar upgrades would be possible for the Eraring and Bayswater units, increasing the capacity of the units to 750MW. We have assumed upgrades at Bayswater, although by only about 50 MW per unit. For Eraring, we assume upgrades to 750 MW per unit but we still apply the same derating in summer to mimic the current operating constraints due to lake temperature. These upgrades have been included as new capacity options in the expansion plan, with an incremental cost of about $500/kW.

B.1.5 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.

B.1.6 Interconnections

Assumptions on interconnect limits are shown in Table B-3. These 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 Wambo Braemar, and the limit to flow into Tarong[15]. During the summer of 05/06 NEMMCO estimates the combined northward capability on QNI and Directlink to be approximately 280 MW, and by 2007/08 this limit was expected to be negative, implying that the limits are forcing QNI to export into NSW. 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.
- Construction of a new transmission line from Middle Ridge to Greenbank, installation of a second transformer at Middle Ridge and upgrades to the existing transformer, to collectively increase northward flow on QNI by 700MW and increase the Tarong limit (from Tarong to Queensland South) by 450MW.
- Network augmentation through series compensation in South East Queensland to offset reductions in transfer capability following commencement of Kogan Creek.
- Works to maintain Directlink's export capability to 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.

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15 There is currently expected to be a limit of about 900 MW for flow into Tarong. This is not a fixed limit and could be increased with additional load shedding in Queensland.

- A 600 MW upgrade of the Snowy to Victoria transmission link over time which would enable additional imports from Snowy/NSW into Victoria. The first 400 MW stage was completed by VENCorp as the regulated SnoVic facility in December 2002. This option has been further developed to include options with augmentation of 180 MW and then up to 2500 MW total transfer from Snowy to Victoria.

Table B-3: Interconnection Limits – based on maximum recorded limit in 2004/05

From	To	Date	Capacity	Summer
Victoria	Tasmania		480 MW	
Tasmania	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	NSW		3465 MW	3127 MW
NSW	Snowy		1150 MW	
NSW	South Queensland		180 MW	
South Queensland	NSW		195 MW	
NSW	Tarong (QNI)		621 MW	
Tarong	NSW (QNI)		1078 MW	

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 expansion that are lower cost than increasing generation within constrained regions.

B.1.7 Transmission losses

Inter-regional 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

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.

B.1.8 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. 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 B-4 shows the monthly energies used in our Strategist model. Table B-5 shows the annual energy for the Snowy Scheme.

Table B-4: 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
Jan	13.96	4.19	18.75	23.32	24.98	19.13	10.01
Feb	20.56	3.44	15.19	22.91	26.37	14.71	10.6
Mar	22.63	0.22	14.53	23.60	11.87	15.51	5.98
Apr	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
Jun	9.40	0.00	0.09	25.80	9.58	0.32	19.4
Jul	10.07	0.94	0.01	32.05	36.78	0.88	28.89
Aug	7.93	4.47	1.09	30.18	34.77	3.3	23.06
Sep	8.51	7.86	6.97	22.61	31.76	4.98	30.8
Oct	12.02	6.71	14.61	23.34	33.33	7.4	43.71
Nov	13.38	3.47	20.25	21.30	35.99	8.98	23.03
Dec	10.52	5.91	20.66	28.05	31.14	17.6	15.93

Table B-5: Annual Energy Limits from Snowy Hydro

	Blowering	Guthega	Murray	Upper Tumut	Lower Tumut
Annual Limit	240	250	2210	1,630	745

(GWh)					

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.

Table B-6: 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.

B.2 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.

B.2.1 Trading arrangements

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

- An energy trading market.

- 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. Considering these features, the main trading platform is a bilateral contracts market, supported by a residual day ahead trading market (called the STEM). This residual trading market allows contract participants to trade out any imbalances, and also allows small generators to compete where they would otherwise not be able to, due to their inability to secure contracts.

Market participants 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 is required to determine the least cost supplies to satisfy the system security requirements. Both independent generators and state generation could be ancillary reserve providers.

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 115MW with the largest cost disproportionately allocated to the largest unit.

B.2.2 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.

B.2.3 Structure of generation

The State Generator, Verve Energy, has been disaggregated vertically from the rest of Western Power but not horizontally. Horizontal disaggregation may still be deemed necessary if it is considered that a single state generator has excessive market power. 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.

Based on this discussion, our assumptions for analysis are:

- To allow a new base load plant to replace Kwinana A in December 2008, with ownership by Newgen, an IPP with a long-term contract for the output of the station.
- To allow Western Power to bid for new entry generation as long as its overall generation capacity does not exceed 3,000 MW.

B.2.4 Demand assumptions

Three key demand parameters are used in the model:

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

We use WA IMO's median case energy sent out forecasts for the SWIS contestable market and Western Power Franchise for the period 2015/16, thereafter extrapolating the trend growth rates.

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. The annual compound growth rate for total electricity demand in the SWIS is around 3.5% (or 3.1% if including the Alcoa loads).

Projections of the summer and winter peak demand at generator busbar are derived from forecasts of sent out peak demand provided by the IMO.

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.

B.2.5 Generation assumptions – existing units

Verve Energy

Verve Energy has 11 power stations operating in the SWIS, as shown in Table B.7. The Muja stations operate as base load stations with capacity factors of 70 - 95%. The Kwinana steam plants and the Mungarra gas turbine operate as intermediate plants with capacity factors of about 40%, while the Pinjar gas turbines operate as peaking plant with 10 - 20% capacity factor. Cogeneration plants are also assumed as "must-run" plants due to steam off-take requirements.

The South West Cogeneration Joint Venture is comprised of 50% Origin Energy and 50% Verve Energy. Approximately 30MW of electricity in supplied to the alumina refinery, with the remainder being supplied to domestic customers via the SWIS. Steam from the cogeneration plant is used in the alumina refinery process and also in its own station. This is a 130MW coal-fired plant owned by Worsley Alumina.

The Kwinana A and C stations are modelled to be able to burn both coal and gas.

The physical characteristics and the fixed and variable operating and maintenance costs for each plant are shown in the following tables.

Table B- 7: Power plant operating assumptions

Station	Type	Capacity in summer peak, MW sent out	Fuel	Maintenance (%)	Forced outage (%)	Heat rate[2] GJ/MWh
Albany	Wind turbine	12 x 1.8	renew.	-	3	-
Collie A	Steam	304	coal	6	2	10.0
Muja C	Steam	2 x 185.5	coal	4	4	11.0
Muja D	Steam	2 x 185.5	coal	4	3	10.5
Kwinana A	Steam	2 x 103.5	coal, gas	5	5	11.0
Kwinana C	Steam	2 x 180.5	coal, gas	4	6	10.8
Kwinana GT	Gas turbine	16	gas, dist	2	3	15.5
Pinjar A,B	Gas turbine	6 x 29	gas	6	3	13.5
Pinjar C	Gas turbine	2 x 91.5	gas	6	3	12.5
Pinjar D	Gas turbine	123	gas	6	3	12.5
Mungarra	Gas turbine	3 x 29	gas	6	3	13.5
Geraldton	Gas turbine	16	gas, dist	2	3	15.5
Kalgoorlie	Gas turbine	48	dist	2	3	14.5
Worsley[1]	Cogeneration	70	gas	4	2	8.0
Tiwest	Cogeneration	29	gas	6	3	9.0

1 South West Cogeneration Venture – 120MW nameplate, 50% Western Power owned.

2 Heat rates at maximum capacity. Heat rates are on a sent out basis (that is, GJ of energy delivered per unit of electricity sent-out in MWh). Heat rates have been adjusted to be based on the higher heating value of fuels.

Source: Western Power, Annual Report, 2004-05, Perth (and previous issues); estimates of maintenance time, unforeseen outages and heat rates for OCGTs and CCGTs are based on information supplied by General Electric and the IEA.

Table B-8: Fixed and variable operating costs

Station	Unit	Fixed costs ($000s/year)	Variable costs ($/MWh)
Albany	0	0	
Collie	A	5,000	4.00
Muja	C	5,500	5.50
	D	5,500	5.00
Kwinana	A	6,500	8.00
	B	4,000	8.00
	C	8,000	7.00
	GT	250	9.00
Pinjar	A,B	500	4.00
	C	1,500	4.50
	D	1,500	4.50
Mungarra		500	4.00
Geraldton		250	5.00
Kalgoorlie		250	5.00
Wellington		0	5.00
Worsley		1,500	4.00
Tiwest		500	4.00

Source: Derived by MMA to match operating and maintenance cost data contained in Western Power Annual Reports.

Other generators

Private generating capacity, including major cogeneration, is detailed in Table B-9. The capacity is mostly comprised of gas-fired generation. There has been a large increase in privately-run generating capacity due to substantial falls in gas costs and the gradual deregulation of the generation sector. Over the 1996-97 period, some 324 MW of privately-owned generation capacity was commissioned, at Kwinana and the Goldfields.

The 116 MW BP/Mission Energy cogeneration project commenced operation in 1996. The BP host takes 40 MW of power, with the remaining 74 MW of power being taken by Western Power under a long-term take or pay agreement. About 3 PJ pa of fuel for the 40 MW portion of output is natural gas purchased directly from the NWSJV, and other inputs include refinery gas.

Power generation from gas in the Goldfields commenced in 1996. Southern Cross Power generates from 4 x 38 MW LM6000 gas turbine stations for its Mount Keith, Leinster, Kambalda nickel mines and its Kalgoorlie nickel smelter. The stations are expected to use about 14 PJ of gas pa (37 TJ/d), sourced from the East Spar field. Goldfields Power has constructed 110 MW of capacity (3 x LM6000 gas turbines) east of Kalgoorlie to supply the SuperPit, Kaltails and Jubilee gold projects.

Table B-9: Generating plants over 10 MW capacity in the SWIS

Company	Fuel	Capacity in summer peak, MW sent out	Maintenance (weeks per year)	Forced outage (%)	Heat rate GJ/MWh

Alcoa	gas	212	3.8	2	12.0
BP/Mission	gas	100	3.8	2	8.0
Southern Cross	gas	120	3.8	4	11.7, 12.7
Goldfields Power	gas	90	3.8	1	9.5
Worsley	gas	27	3.8	2	8.0
Wambo Power	gas	350	3.0	2.0	7.4
Kemerton	Gas, liquid fuel	308	1.0	1.5	12.2
Alinta Wagerup	Gas	351	3.0	2.0	11.2
Alinta Pinjarra	Gas	266	2.0	2.0	6.5
Bluewaters	Coal	200	3.0	3.0	9.7

Source: Capacity data from publications published by the WA Office of Energy, MMA analysis based on typical equipment specifications published in Gas Turbine World.

Most of the plants are located near major industrial loads. Some wheeling of power is also undertaken. BP/Mission's cogeneration plant at Kwinana supplies electricity to Western Power. Consequently, this cogeneration plant is treated as a 'must-run' unit. Other units treated this way include Tiwest and Worsley.

B.2.6 Derating of units

The capacity of the gas turbines is affected by temperatures at the inlet of compressors – the hotter the temperature at the inlet, the lower the capacity. The average monthly deratings, as a percentage of rated capacity, are shown in Table B-10. The same deratings are applied to all OCGTs, except for the Alcoa units. The Alcoa units are de-rated to a lesser degree, as are CCGTs and cogeneration plant. Coal units are similarly derated over the warmer months, though not as much.

Table B-10: Monthly deratings – percent of maximum capacity

	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun
OCGT	0	0	10	11	13	16	18	18	16	13	11	0
CCGT	0	0	7	7	9	11	12	12	11	9	7	0
Coal	0	0	0	0	3	4	5	5	4	0	0	0

Source: Based on data provided by NEMMCO for comparable units and aggregate data published by the WA Independent Market Operator.

B.2.7 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.

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.

Nominal coal prices are assumed to increase by 100% of the inflation rate.

Delivered gas prices consist of a component for gas supplied under the North West Shelf Joint Venture (NWSJV) contract and a transport component.

Three types of gas are represented in the SWIS model:

- "Gold gas", used by the stations in the Goldfields region
- "Existing gas" used by existing plants in the Perth region prior to 2007 when a new gas contract started
- "New gas", used by all other gas stations in the system.

MMA assumes that new gas supply will be priced at $6.95/GJ in 2007 dollars with price escalating at 100% of the CPI increase. 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 $6.95/GJ. There is assumed to be no limit on gas transmission – additional capacity will be added as required. 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.

B.3 Darwin Katherine System

B.3.1 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 onsell 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).

The dispatch and system control functions is undertaken by the network company of PWC (PWC Networks).

PWC acts as the residual generator, absorbing over generation and making up shortfalls in generation, and is paid a regulated fee for this service.

B.3.2 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.

There are currently two generators in the system, PWC and EDL who operates two power stations and sells all its electricity through PWC.

B.3.3 Economic Dispatch

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.

B.3.4 Generation

Generation in the Darwin-Katherine Interconnected System consists largely of gas-fired gas turbines supported by oil fired turbines and diesel generators. The relatively small load in the region results in generating units of relatively small size, the largest being a 37 MW gas turbine at the Channel Island power station in Darwin.

Table B-11: Installed generation

Unit	Maximum Capacity (MW)	Heat Rate at Maximum (MBTU/MWH)	Maintenance Requirement (Weeks/Year)	Mature Forced Outage Rate (%)	Fixed Costs ($000/YR)	Fuel Cost, 2010 ($/GJ)	Variable O & M Costs ($/MWH)
CI GT 1	32	14.0	2.0	2.0	433	6.80	3.0
CI GT 2	32	14.0	2.0	2.0	433	6.80	3.0
CI GT 3	32	14.0	2.0	2.0	426	6.80	3.0
CI CC 1	48	8.0	2.0	2.0	2796	6.80	1.3
CI CC 2	48	8.0	2.0	2.0	2796	6.80	1.3
CI GTD 1	45	11.5	2.0	2.0	499	6.80	5.0
BERRIMGT 1	15	16.5	2.0	2.0	168	6.80	11.5
BERRIMGT 2	15	16.5	2.0	2.0	168	6.80	3.0
KATHERGT 1	7	16.5	2.0	3.0	73	7.00	3.0
KATHERGT 2	7	16.5	2.0	3.0	73	7.00	3.0
KATHERGT 3	7	16.5	2.0	3.0	73	7.00	3.0
PINECRCC 1	14	9.0	2.0	2.0	699	6.80	3.0
PINECRCC 2	14	9.0	2.0	2.0	673	6.80	3.0
PINECRGD 1	3	11.5	2.0	2.0	30	6.80	5.0
PINECRGT 1	2	17.0	2.0	3.0	30	6.80	4.0
PINECRGT 2	2	17.0	2.0	3.0	30	6.80	4.0
PINECRGT 3	2	17.0	2.0	3.0	30	6.80	4.0
Wendell 1	40	11.5	2.0	2.0	30	6.80	3.0
Wendell 2	40	11.5	2.0	2.0	30	6.80	3.0
Wendell 3	30	11.5	2.0	2.0	30	6.80	3.0
LM6000 1	34	11.5	2.0	2.0	2796	6.80	3.0

Source: PWC Annual Reports; NT Utilities Commission; ESAA (2001), Electricity Australia 2001, Sydney.