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Benefits and Costs of the Expanded Renewable Energy Target

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ABBREVIATIONS

CoPS	Centre of Policy Studies
CPI	Consumer Price Index
CPRS	Carbon Pollution Reduction Scheme
DKIS	Darwin Katherine Interconnected System
ERET	Expanded Renewable Energy Target
GDP	Gross Domestic Product
GHG	National Greenhouse Gas
GNP	Gross National Product
IGCC	Integrated Gasification Combined Cycle Plants
IMO	Independent Market Operator
MMA	McLennan Magasanik Associates
MRET	Mandatory Renewable Energy Target
NEM	National Electricity Market
NGGI	National Greenhouse Gas Inventory
REC	Renewable Energy Certificate
REMMA	Renewable Energy Market Model Australia
RET	Renewable Energy Target
SHW	Solar Hot Water
SWIS	South West Interconnected System
TWA	Time Weighted Average
VOLL	Value of Lost Load
VREC	Victorian Renewable Energy Certificates
VRET	Victorian Renewable Energy Target

EXECUTIVE SUMMARY

The Australian Government intends to implement an expanded Renewable Energy Target (RET) scheme, with an ultimate target in 2020 of 45,000 GWh. A preferred design for the scheme was published in an exposure draft of the intending legislation. MMA was commissioned by the Federal Government to assess the benefits and costs of the preferred design on the electricity market and on the broader economy.

In order to examine the implications of the preferred design, two scenarios were modelled. These scenarios are:

- *Reference scenario* (called *"the reference scenario"* in this report): CPRS is implemented but the expanded RET target is not implemented[1]. The current MRET scheme and the Victorian Renewable Energy Target Scheme continue as planned. The carbon price path trajectory rises from \$20/t CO_2e in 2010/11 to \$34/t CO_2e in 2020, \$51/t CO_2e in 2030 and ultimately to \$114/t CO_2e in 2050. The assumptions underpinning the CPRS are those used by MMA in the modelling of emissions trading undertaken for the Federal Treasury[2].
- *RET Preferred Design* (called *"CPRS + RET scenario"* in this report): Renewable energy target expands in dual linear fashion to 45,000 GWh in 2020. The scheme ends in 2030. Solar water heaters remain eligible throughout the life of scheme. Generators eligible to earn certificates under the current MRET and VRET schemes and which created certificates before January 2008 remain eligible until the end of the scheme. There are no limits on banking and on the period with which generators can earn certificates.

Method

Details of the method are outlined in the main report. Essentially there is a three step process to the modelling:

- Step 1: Renewable energy market modelling (using MMA's REMMA model). This model determines the mix of renewable energy technologies that meets the cumulative target over the life of the expanded RET scheme at least cost to the market, subject to any restrictions contained in the scheme design. Outputs from this modelling include the mix of renewable energy generation by technology by State and the certificate price required to allow the target to be met. The certificate price is set by the long run marginal cost (minus the electricity price received for its output) of the last generator required to meet the target.
- Step 2: Electricity market model simulations. Using the outputs of the renewable energy capacity by State in MMA's Strategist model of the Australian electricity

1 The emission target is the CPRS -5 scenario as modelled by the Federal Treasury.

2 See MMA (2008), *Impacts of the Carbon Pollution Reduction Scheme on Australia's Electricity Markets*, report to Federal Treasury, 11 December.

markets, simulations of the wholesale electricity market are performed to determine impacts on electricity price, investments in new conventional generation technologies and resource costs.

- Step 3: Using outputs from the electricity market model (wholesale price impacts, generator investments by technology type) as well as the resource costs from implementing more expensive renewable energy technologies (calculated as the REC price times the additional renewable generation required to meet the target), the MMRF model of the Australian economy is used to determine the impacts on Gross Domestic Product (GDP), Gross National Product (GNP) and employment.

The process is repeated in an iterative fashion until stable results are achieved.

Key assumptions

The same assumptions set used for the Treasury modelling of the CPRS are used in this analysis.

Some high level assumptions include:

- The market operates to maximise efficiency and is made up of informed, rational participants.
- MMRF's energy demand forecasts for the reference scenario are used in all scenarios. Annual demand shapes are then derived to be consistent with the relative growth in summer and winter peak demand implied in the NEMMCO, Western Australian Independent Market Operator and NT Utilities Commission's forecasts of electricity demand.
- Capacity is installed to meet the target reserve margin for the NEM, SWIS and the DKIS, subject to entrants being profitable over their operating life.
- The study period is 2010 to 2050.
- Availability, heat rates and capacity factors of all plants in the NEM, SWIS and DKIS (including non-renewable generators) are based on historical trends and other published data.
- The capacity factor for existing hydro generators is assumed to be based on normal inflow conditions, with assumptions for Tasmania updated. Capacity factors for wind generation vary by state and location and vary from 28% to 43%.
- Fuel prices for gas generators are estimated using MMA's gas market model, moving in line with Treasury's assumptions of world gas prices.
- Assumed fuel prices for coal generators are based on published data on prices (such as ABARE's export coal price projections) and published data on contract quantities, with prices increasing in line with world coal prices (except for mine mouth power stations, where prices remain steady) as assumed in the Treasury modelling.

- Non-fuel operating costs are estimated based on published data and bid information.
- Capital costs for thermal generation options are based on published data and industry knowledge. Existing clean coal technologies, such as Integrated Gasification Combined Cycle Plants (IGCC) are included as options in cost estimates. IGCC plant fitted with pre-combustion carbon capture and storage, is also considered.
- Costs for renewable generation projects are derived from published sources of information. MMA maintains a database of renewable energy projects, which contains information on capacity, generation levels, operating costs, capital costs and other costs for each renewable generation project - operating, committed or planned. The location – by sub-state region – is also known, and incorporated into the model.
- Real capital costs for all technologies are assumed to fall over time. A "capital cost reduction factor" is included for each technology in the analysis to model this effect, with the reduction factor specific to the technologies.
- Future transmission and distribution prices are estimated from historical trends in prices and recent regulatory decisions on allowable movements in prices (under the CPI-X provisions).
- Inter regional network upgrade costs are based on the Annual Planning Statements published by the State jurisdictions and planning bodies. The data was used to make assumptions on the costs of both committed and planned interregional network upgrades.
- Greenhouse gas emissions per generating unit are estimated based on National Greenhouse Gas Inventory (NGGI) data on emission intensity per unit of fuel used.
- Any changes in wholesale prices will flow through to retail prices. Price increases are therefore borne by the broad customer base.

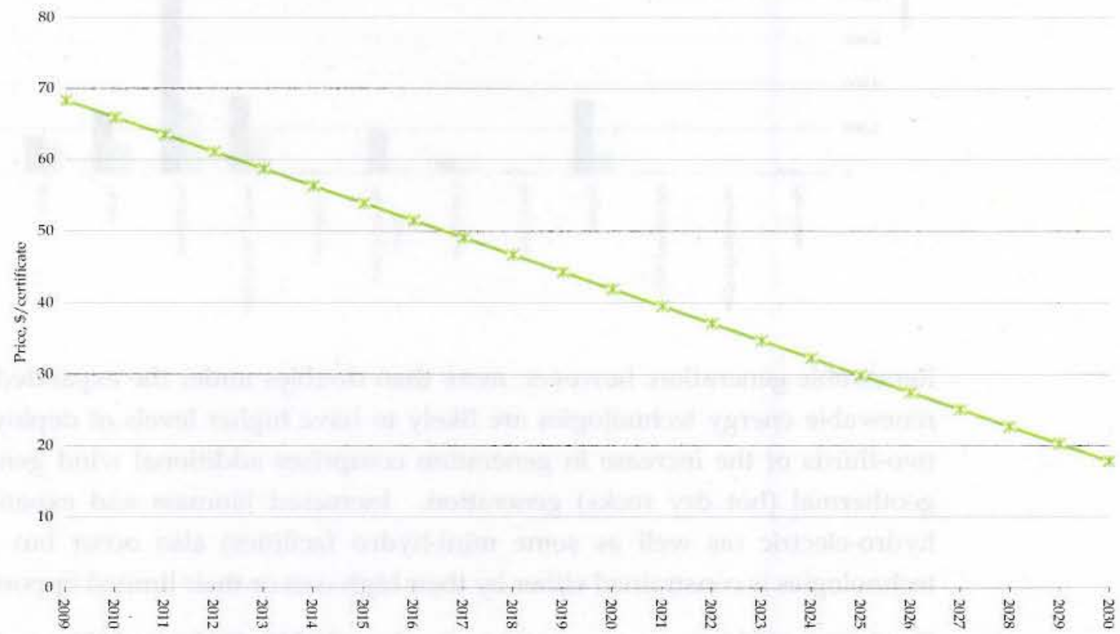
Impact on renewable energy mix

Certificate prices

Certificate prices are shown in Exec Figure 1. With the implementation of the CPRS, certificate prices under the existing MRET/VRET target are expected to fall. This occurs because the higher electricity prices wrought under an emissions trading scheme decreases the revenue required from support measures such as MRET. Under competitive market assumptions, this drives down the price for a certificate because the net unit revenue of the last generator required to set the price falls. The price of the REC falls from $40/MWh in 2009 to $0/MWh in 2019.

Under the expanded RET scheme, prices start off at around $70/MWh and then decreases over time[3]. The high initial price occurs because this is the price required to get the additional renewable generation in the early years of the scheme when the outlook is for decreasing certificate prices over time. A high initial certificate price is required for early entrants to recoup more of its capital costs in the early years than in the latter years of the scheme.

Exec Figure 1: Certificate prices for CPRS + RET



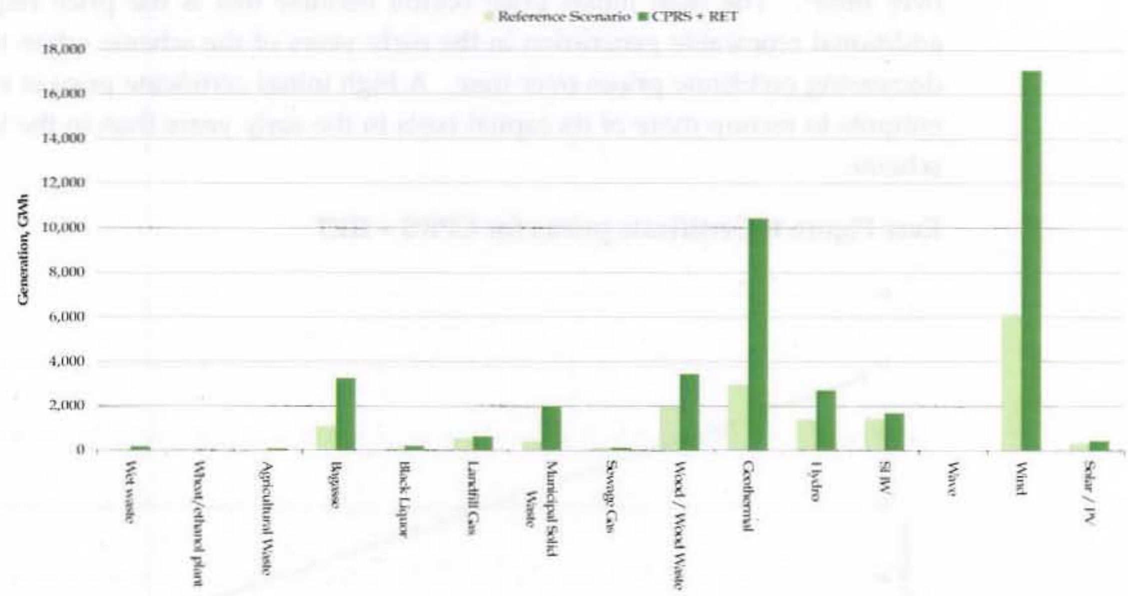
The decreasing price path is explained by a number of factors. First, electricity prices are expected to increase slowly over time, so that the revenue required under the RET to recover investments costs decreases over time. This is partly offset by the increasing cost of renewable energy as the target increases, but this cost increases at a slower rate than the price of electricity. Second, because many of the renewable energy generators continue to operate after the end of the expanded RET scheme, they can earn additional revenue from the electricity market as prices continue to rise after the expiry of the expanded RET.

Renewable energy technology mix

Renewable energy generation is set to expand markedly both as a result of the expanded RET and the CPRS. Even without the expanded RET, there is a small increase in the level of renewable energy generation by 2020, of around 7,000 GWh above under the current MRET scheme. The increase is due to the implementation of the VRET scheme, the continuing growth in Green Power sales and the incentives from higher electricity prices brought about the CPRS (which is sufficient to encourage some low cost renewable energy options).

3 The price in each year reflect long term contract prices for certificates that are required to support the renewable energy generators that enter the market in each year.

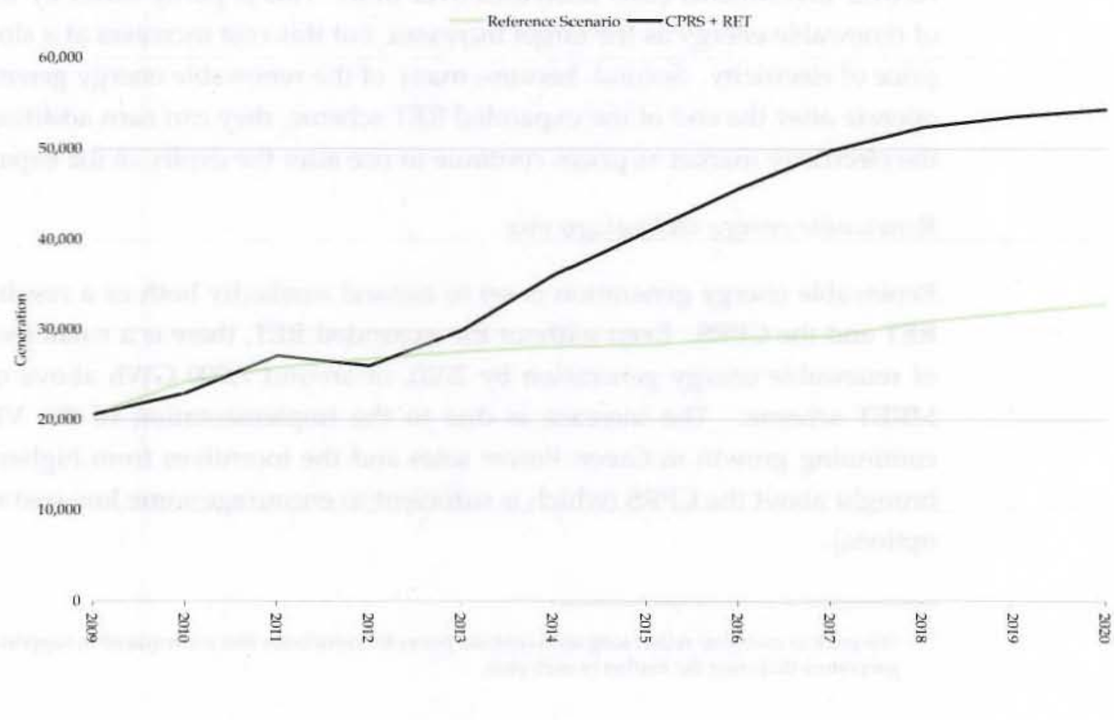
Exec Figure 2: Renewable energy technology mix (excluding pre-1997 generation), 2020



Renewable generation, however, more than doubles under the expanded RET target. All renewable energy technologies are likely to have higher levels of deployment, but about two-thirds of the increase in generation comprises additional wind generation and new geothermal (hot dry rocks) generation. Increased biomass and expansions at existing hydro-electric (as well as some mini-hydro facilities) also occur but growth in these technologies is constrained either by their high cost or their limited opportunities.

Total renewable energy generation reaches 54,300 GWh in 2020, or 20% of the total generation of electricity (on a sent out basis) projected for that year.

Exec Figure 3: Total renewable energy generation in Australia, sent out basis



In the absence of the RET scheme, the same level of investment in renewable generation would not occur until 2035. The RET brings forward investment in renewable generation that would eventually occur over a longer time frame, or with higher carbon prices.

Impacts on electricity markets

The expanded RET scheme has a modest impact on electricity prices. Wholesale electricity prices for the period 2010 to 2020 average $65.9/MWh in the Reference scenario and $66.2/MWh for the CPRS + RET scenario. The difference in price is less than 1% over the entire period. The impact of RET is limited as additional renewable generation is matched by deferment of fossil fuel generation capacity and retirement of some existing plant.

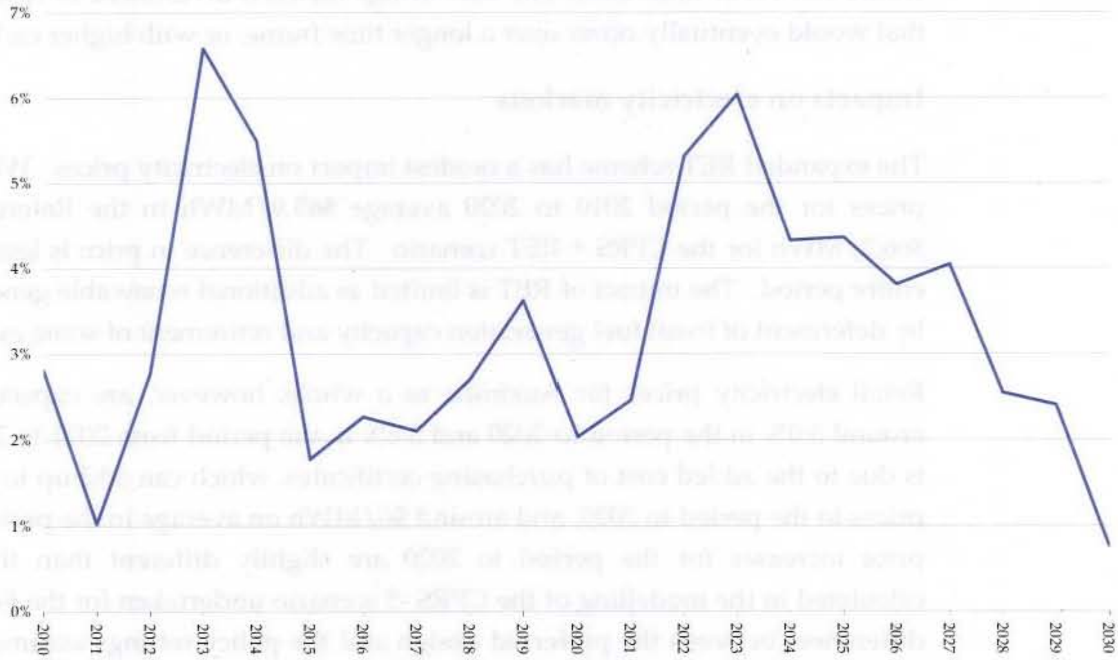
Retail electricity prices for Australia as a whole, however, are expected to increase by around 3.0% in the period to 2020 and 3.6% in the period from 2021 to 2030. The increase is due to the added cost of purchasing certificates, which can add up to $4/MWh to retail prices in the period to 2020, and around $6/MWh on average in the period after 2020. The price increases for the period to 2020 are slightly different than the price increases calculated in the modelling of the CPRS -5 scenario undertaken for the Federal Treasury as differences between the preferred design and the policy settings assumed in the Treasury modelling result in slightly different certificate prices. With existing generators eligible to earn certificates in the period to 2030 (which was not assumed in the Treasury modelling), there is less market demand for certificates under the declining target trajectory for new generators to earn the required amount of revenue in the period after 2020. Thus, in order for new generators to recover their investment costs over a reduced market, they need higher REC prices.

Exec Table 1: Impact of expanded RET on retail electricity prices, Australia

	2010 -2015	2016 -2020	2021-2030
Average prices, $/MWh			
Reference scenario	115	145	165
CPRS + RET	119	149	171
% change due to RET	3.5%	2.6%	3.6%

Note: Retail prices are averaged across customer classes in each state by volume of consumption in each customer class. Regional average prices are then weighted by the volume of generation in each region to get Australia wide averages.

Exec Figure 4: Change in average retail electricity prices, Australia wide average



Wider economic impacts

GNP is reduced by around $0.2 billion per annum as a result of the expanded RET. This reduction represents a reduction in GNP of around 0.01%. The present value of the change in GNP is estimated to be $2.4 billion for the period to 2030[4].

GDP impacts for Australia and the States are compared in Exec Table 2. The impacts depend on two offsetting impacts: the increase in energy prices and deferment in fossil fuel investment (which reduces GDP) and the level of investment in renewable energy (which can add to GDP). Overall there is a small reduction of 0.04 % in GDP. The biggest reduction occurs in Victoria and Northern Territory, the former because of the impact on energy costs plus deferment in new capacity and the latter because of high energy costs only (as no new renewable investment occurs in that state prior to 2020). Tasmania exhibits a small benefit due to the investment of new wind capacity.

[4] Calculated using a 8% discount rate over the period to 2030.

Exec Table 2: GDP impacts of the expanded RET, 2010 to 2030

	Present value of change to GDP, $ million	% change in GDP
Australia	-5,796	-0.04
NSW/ACT	-1785	-0.04
Victoria	-3,222	-0.10
Queensland	-543	-0.01
SA	406	0.04
WA	-1,087	-0.07
Tasmania	580	0.28
NT	-126	-0.08

Source: CoPS

1 INTRODUCTION

The Department of Climate Change has engaged McLennan Magasanik Associates to conduct economic and electricity market modelling of proposed design options for the expanded Renewable Energy Target (RET) scheme.

The modelling and analysis is designed to provide information on national and state impacts of scheme design, including:

- Economic costs.
- Investment profile.
- Technology mix.
- Network infrastructure.
- Greenhouse gas abatement.
- Electricity prices.

The modelling has been used to test the impacts of the interaction of various scheme design parameters, to inform a single final design. The impacts of the final design are discussed in this report.

2 METHOD AND ASSUMPTIONS

2.1 Overview

The same method and assumptions used in the modelling of the CPRS for the Federal Treasury has been used in this study (a report outlining this approach is on the Federal Treasury's website[5]). Essentially there is a three step process to the modelling:

- Step 1: Renewable energy market modelling, using MMA's REMMA model. This model determines the mix of renewable energy technologies that meets the cumulative target over the life of the expanded RET scheme at least cost to the market, subject to any restrictions contained in the scheme design. Outputs from this modelling include the mix of renewable energy generation by technology by State and the certificate price required to allow the target to be met. The certificate price is set by the long run marginal cost (minus the electricity price received for its output) of the last generator required to meet the target.

- Step 2: Electricity market model simulations. Using the outputs of the renewable energy capacity by State (from the REMMA model) in MMA's Strategist model of the major electricity markets in Australia, simulations of the wholesale electricity market are undertaken to determine impacts on electricity price, investments in new conventional generation technologies and resource costs.

- Step 3: Using inputs from the electricity market model (wholesale price impacts, generator investments by technology type) as well as the resource costs from implementing more expensive renewable energy technologies (calculated as the REC price times the additional renewable generation required to meet the target), the MMRF model of the Australian economy is used to determine impacts on Gross Domestic Product (GDP), Gross National Product (GNP) and employment.

The process is repeated in an iterative fashion until stable results are achieved.

To accurately measure the economic impacts of the RET on both the electricity market and the broader economy, the CPRS has been included. Therefore, the results show the impact of the RET being introduced in addition to the CPRS. Outcomes of the modelling such as cost impacts are presented as additional impacts to those that would result from the CPRS alone.

2.2 Modelling Impacts on the Electricity Market

The second stage involved detailed modelling of the electricity markets over the timeframe of the study using MMA bottom up models of these markets. MMA's model of

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[5] See http://www.treasury.gov.au/lowpollutionfuture/consultants_report/default.asp

the National Electricity Market (NEM), South West Interconnected System (SWIS) and the Darwin Katherine Interconnected System (DKIS) simulates the market to determine:

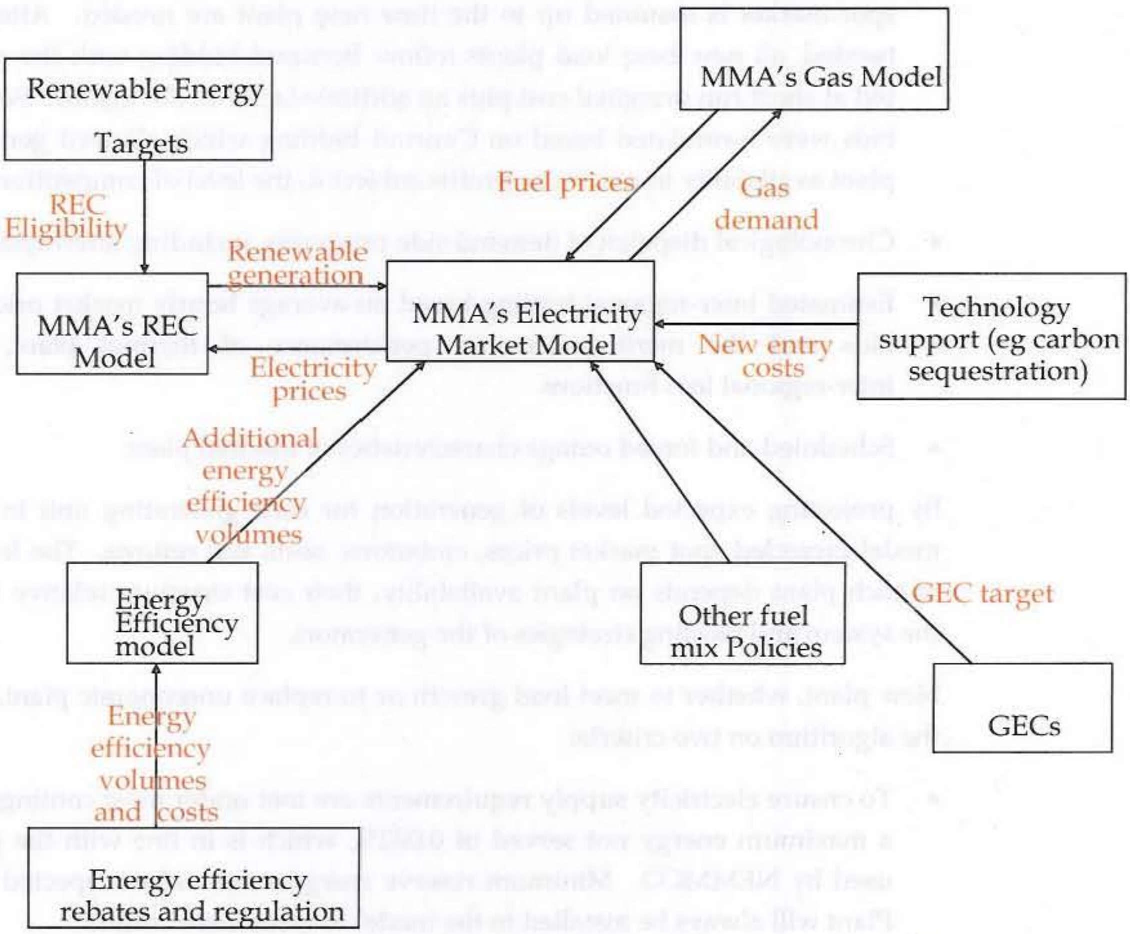
- Dispatch of generating plant and electricity supply costs arising from this dispatch for each year.
- Timing and type of new investments in electricity generation and for each region.
- Impact of schemes such as Queensland's Gas Electricity Scheme and renewable energy targets on dispatch and electricity prices.

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

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

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

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



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

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

- Chronological hourly electricity loads representing a typical week in each month of the year. The hourly load for the typical week is consistent with the hourly pattern of demand and the load duration curve over the corresponding month
- Chronological dispatches of hydro and pumped storage resources either within regions or across selected regions (hydro-electric plant is assumed to shadow price to maximise revenue at times of peak demand)

- A range of bidding options for thermal plant to maximise profit from trading in the spot market is assumed up to the time new plant are needed. After new plant are needed, all new base load plants follow Bertrand bidding with the remaining plants bid at short run marginal cost plus an additive factor in all regions. For existing plants, bids were formulated based on Cournot bidding which allowed generators to adjust plant availability to maximise profits subject to the level of competition in the market.

- Chronological dispatch of demand side programs, including interruptible loads.

- Estimated inter-regional trading based on average hourly market prices derived from bids and the merit order and performance of thermal plant, and quadratic inter-regional loss functions.

- Scheduled and forced outage characteristics of thermal plant.

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

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

- To ensure electricity supply requirements are met under most contingencies. We used a maximum energy not served of 0.002%, which is in line with the planning criteria used by NEMMCO. Minimum reserve margins were also respected for each region. Plant will always be installed in the model to meet these criteria

- Revenues earned by the new plant equal or exceed the long-run average cost of the new generator. Additional plant could be installed according to this criterion above that required satisfying the first criterion.

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

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

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

- Forecasts of load growth (peak demand, electricity consumption and the load profile throughout the year).

- Operating parameters for each plant including heat rate as a function of capacity utilisation, rated capacity, internal energy requirements, planned and unforeseen outage time.

- Data on fuel costs for each plant including mine mouth prices (or well head prices in the case of gas), rail freights (or transmission costs in the case of gas), royalty arrangements, take-or-pay components, escalation rates, quantity limits and energy content of the fuel.
- Variable unit operating and maintenance costs for each plant (which may also vary according to plant utilisation).
- Fixed operating and maintenance costs.
- Emissions production rates by fuel type.
- Annual hydro energy and allocation of generation on monthly basis.
- Capital costs for new generating plant.

2.3 Modelling of the uptake of renewable energy generation

2.3.1 Basis

Under the RET scheme wholesale market customers are required to purchase RECs equivalent to their liabilities under the scheme. The price of the certificates is primarily a function of the cost of supply of renewable generation, the actual level of the generation required to meet the renewable energy target and the structure of the wholesale market and the market for certificates. In this section, we describe the methodology employed to project renewable energy certificate prices and the key underlying assumptions.

The price of renewable energy certificates is affected by a number of factors:

- The nature, cost and available resource of renewable energy.
- Prices received for renewable energy generation in wholesale electricity markets.
- Revenue earned from other potential services provided by renewable generation, such as the ancillary services, avoidance of network costs, avoidance of waste disposal costs and green premiums.
- Short-term factors, such as variation in climate from year-to-year.

Renewable energy technologies are generally characterised by a number of features that will ultimately impact on the price of the certificates. Apart from the capital and operating costs, other factors affecting the choice of renewable generation options and, therefore, the price of certificates include:

- Constraints on fuel resource availability. This particularly impacts on the costs of biomass options, which may need guarantees of long-term fuel supplies. It also affects intermittent generation options, particularly the reliability of supply of the fuel (e.g., wind regimes and solar insolation levels).

- Changes over time in the capital costs of renewable energy technologies. The long-term trend has been for a decline in the capital cost of renewable energy technologies as a result of technological enhancements and increasing scale of production.

- Lag times in developing renewable generation projects (including the time required to obtain approvals).

- Community concerns over the visual amenity or other pollution issues associated with renewable generation.

- Strategic factors that may cause investments in options that are not the least cost options.

Because of the dearth of site-specific information on renewable energy options, some retailers may contract with options with higher cost than would have been chosen on the basis of least cost for the system as a whole. A competitive market for renewable energy with well-informed participants would result in choices converging to least cost outcomes. Prices of certificates would be bound by the entry cost of the next highest cost option required to meet the target. Retailers who contract with higher cost options will face the risk of earning lower profits on their sales of electricity.

Output from renewable generation will either be sold on wholesale markets or will displace purchases from the wholesale market by end-use customers. Thus, renewable generators will receive revenue from electricity sales to wholesale customers.

The value of output for the renewable energy generators will be equal to the prices received in the pool market minus a loss factor covering losses in transmitting the electricity from the generator to the market. In some cases, renewable generators may confer an advantage to customers in lowering the network losses. The renewable generator could also capture part of the value of reduced losses.

Due to the operation of the NEM, the price of electricity varies significantly throughout the day. The highest prices occur at periods of high demand, primarily the morning and evening peaks, and low prices occur overnight as demand reduces. This diurnal cycle of wholesale prices has a large impact on the sales revenue earned by a renewable generator and the certificate price required to support the projects. Some renewable generators may have higher levels of generation during peak periods resulting in a higher average price for sales than a simple daily average. On the other hand, some other renewable generators such as solar hot water systems commonly replace off-peak electric systems, resulting in these generators receiving a much lower average electricity price.

Some renewable generator options, particularly embedded and distributed generators, can provide other market services. Examples include avoided network costs, lower losses, provision of steam from renewable based cogeneration and provision of other products or services (such as waste management).

Of course, intermittent renewable generation options will be less successful in obtaining such additional benefits.

To the extent that renewable generation may confer additional benefits to electricity customers, the value of these benefits will impact on the REC price outcomes assuming a competitive market. The value of these services should fall in the range between the marginal cost of providing the service through renewable generation and cost of the alternative option for providing similar services. However, these additional benefits have not been considered in the modelling.

2.3.2 Method

Projecting renewable energy certificate prices and the technology mix likely under the expanded RET requires the use of a sophisticated model of the Australian electricity system. Our approach is to account for the interrelationships between the wholesale electricity market and the renewable energy market over the study period. Future REC prices are dependent on wholesale electricity market prices and the cost of renewable generation. In turn, the entry into the market of additional renewable generation will impact on wholesale electricity prices.

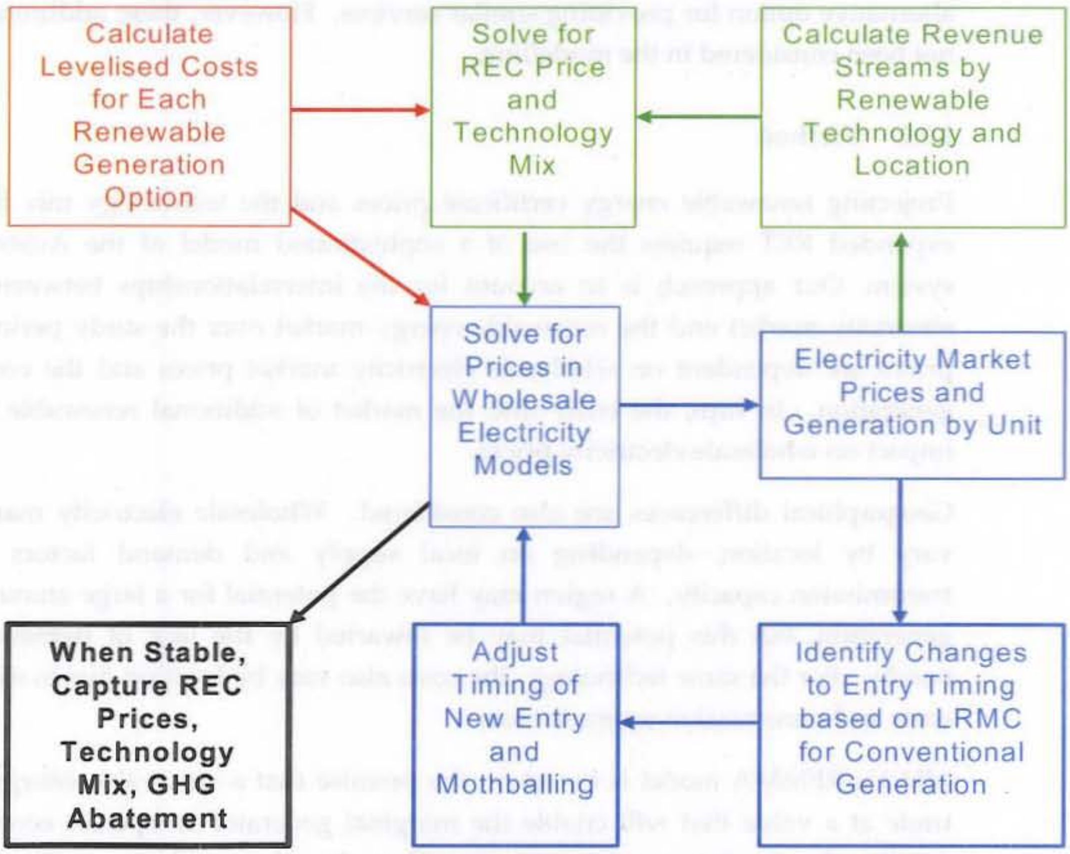
Geographical differences are also considered. Wholesale electricity market prices may vary by location, depending on local supply and demand factors and limits on transmission capacity. A region may have the potential for a large amount of renewable generation, but this potential may be thwarted by the lack of demand for electricity nearby. For the same technology, the costs also vary by location due to differences in fuel costs and transmission upgrade costs.

MMA's REMMA model is based on the premise that a renewable energy certificate will trade at a value that will enable the marginal generator to operate economically, while meeting the mandatory interim targets. The value of a certificate may be determined from the difference between the levelised cost of generation of the marginal renewable generation unit and the electricity price obtained in the market for the thermal generation it displaces. Thus, the basis of the projections of the price of renewable energy certificates is that the certificate price will relate directly to the cost of renewable electricity generation. The renewable certificate will equate to the difference between the cost of the lowest cost renewable energy required to meet the mandatory target and the price for the electricity that can be obtained in the wholesale market. The cost of the last renewable option dispatched to meet each of the interim targets sets the market clearing price and the certificate price.

The prices forecast with this method represent an average price for contracted and spot sales of RECs. Most RECs will be sold under bilateral contracts, with up to 20% of sales traded on the spot market.

An overview of the modelling process is shown in Figure 2-2. The approach is iterative since the timing and selection of renewable generation impacts on wholesale market prices and vice versa. The electricity prices that are produced as an output of the wholesale electricity market simulation model, Strategist, are used as inputs into the REC model. After running the REC model, any changes to the renewable generation options selected are inputted back into Strategist. The process may be repeated if it is deemed that substantial changes in REC price and technology mix are possible.

Figure 2-2: Overview of method for projecting REC prices and technology mix



The approach is based on the assumption that the REC price provides the revenue, in addition to the electricity price, that is required to make the last required (marginal) renewable energy generator to meet the REC target viable. This takes into account an acceptable commercial rate of return to the project developer.

In a simple system the REC price would be determined by identifying the marginal generator and performing a simple subtraction of these two values. However, the following complications arise:

- Introduction of new renewable generators impacts on the electricity price paths, which may require iteration of the market price forecast and the REC estimation.

- The allowance of banking in the REC market results in the requirement for an inter-temporal optimisation. Under the expanded RET, there is no limit on banking so more RECs can be created in a year than required to meet the target to be banked and surrendered at a later date. This makes economic sense if the cost of creating the REC earlier than required is lower than the projected cost of purchasing a REC at a future date. The potential for banking means that the demand for renewable generation can be higher than the interim targets in the earlier years and lower than the target in the latter years. The effect of banking in terms of REC prices will depend on the level of banking and the costs avoided from creating surplus RECs.

- Currently, installed and committed generators remain/enter the market regardless of the estimated economics. Because capital costs are sunk, these plants are assumed to be operating with just the marginal cost of generation considered in the modelling. Typically, these marginal costs are lower than the levelised costs for new units, so that committed plant are not likely to set the price in RECs in any year[6].

- Generation resulting from the upgrade of large hydro units is treated in our hydro dispatch model to account for the additional dispatch that could be achieved with refurbishment to achieve higher efficiency in generation. This means that the additional capacity is treated as new generation capacity in the model, with full accounting of all costs incurred in the upgrade.

- Resource and other constraints limit the uptake of renewable generation. Resource constraints, for example fuel availability, are modelled by increasing the marginal cost of the resource.

The certificate price path is set by the net cost of the marginal generators, which enable the above conditions to be met and result in positive returns to the investments in each of the projects.

MMA has a detailed database of renewable energy projects covering existing, committed and proposed projects that supports our modelling of the REC price path. The database includes estimates of capital costs, likely reductions in capital costs over time, operating and fuel costs, connection costs, and other variable costs for individual projects that are operating, committed or planned[7].

For this assignment, the data base was updated and revised. Currently, the data base comprises:

- 466 eligible renewable generators, either existing, committed or planned.

- Existing RE generation accounts for 6,536 GWh per annum of eligible (above baseline) REC creation (excluding the proportion of generation sold on Green Power markets).

- Committed projects account for a further 3,326 GWh eligible REC creation, with most of this generation coming into the market by the end of 2009.

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6 The marginal cost of an existing plant typically comprises only fuel and non-fuel operating costs (capital costs are sunk). For new plant that is not as yet in the market, the marginal cost includes the cost of capital because the plant would need to recover capital costs to enter the REC market.

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

- Planned or generic projects, excluding additional solar hot water sales, amounting to 185,000 GWh of eligible renewable generation.

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

MMA has also developed a separate model for forecasting REC creation from solar water heaters taking into account the impact of a range of support policies.

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

- The costs of a range of renewable energy generation options have been determined as the levelised cost of generation using a 9.8%[8] real pre-tax weighted average cost of capital over at most a 20-year investment horizon. The model considers the time from the commencement of generation to the end of 2030 for REC revenue but only considers energy (electricity) revenue beyond 2030 earned by the project if its operating life goes beyond 2030. Where data has been available, the costs include the costs of connection to the grid, which can form a significant proportion of the capital costs of a project, particularly where no local transmission wires are available (up to $15/MWh for remote projects).

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

- Assign regional wholesale electricity prices to all renewable projects in the data base according to location and start date. Weight wholesale electricity prices according to the generation profile of the renewable technology. For example, waste process generation would operate 24 hours per day and would therefore be represented by the average time-weighted pool price. Whereas, photovoltaic would only operate through daylight hours, achieving the prevailing market price for these hours only. Solar hot water systems although using solar energy during daylight hours, actually replace off-peak electricity usage so the surrogate price for this option is the off-peak price for the replaced energy.

- For each project, estimate any revenue from other sources such as fees for avoided landfill charges.

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

- Potential revenues from wholesale market transactions and other sources for each project are levelised for the life of the project.
- Subtract levelised revenue from corresponding renewable project levelised cost and then determine the merit order of the projects by ascending net costs (apart from those generators flagged as committed). The generation meeting the interim targets plus demand for banked credits in each year will determine which projects in the merit order will come on-line in a particular year.
- The generation output from each project is calculated from the MW and capacity factor for each project.
- For each selected new project the REC values over the remaining term of the expanded RET Scheme are discounted with the electricity sales income. The discounted cash flow compared with the levelised cost indicates whether a given REC price path will justify the construction of a project.
- The REC path is optimised over the years of the program subject to the constraints indicated above.
- The plant installed in each year is determined by the economic viability subject to the REC price path, REC creation and surrender constraints.
- The resulting installed capacity and generation levels are then input into wholesale electricity market model to determine the resultant pool price changes that in turn impact the REC prices.
- The process may be repeated until stable outcomes result.

In this analysis banking of certificates over periods is allowed to occur where economic. This allows generators to hold their certificates until a later date when a more attractive price may be available. Banking of certificates may also reduce the total cost of the scheme by delaying the introduction of more expensive generation. It also means that all targets could be met by a group of renewable generators creating less than overall target.

2.4 General assumptions

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

2.4.1 Market Structure and Modelling Approach

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

The study period is 2005 to 2050, with the emissions trading policy assumed to commence in July 2010.

Capacity is installed to meet the target reserve margin for the NEM, SWIS and the DKIS as long as new entrants recover all costs.

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

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

2.4.2 Demand

The MMRF model supplies an energy demand forecast by industry classification and State for each scenario. Annual demand shapes are then derived to be consistent with the relative growth in summer and winter peak demand implied in the NEMMCO, Western Australian Independent Market Operator (IMO) and NT Utilities Commission's forecasts of electricity demand. The growing trend in "peakiness" of demand forecast in the short-term was extrapolated to 2025, with the average to peak demand ratio sustained at the 2025 value for the remainder of the projection period.

The proportion of the load that is on the major grids is determined from Annual Reports and NEMMCO data.

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

2.4.3 Renewable Technologies

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

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

Both existing (hydro, wind, biomass, SHW) and predicted technologies (geothermal, high temperature solar thermal and wave) were considered, with capacity limitations as determined by previous MMA research. There are limited new hydro-electric and biomass resources, with the latter limited by host industry expansion and fuel transportation costs.

Aside from the constraint of above, wind resources will eventually be limited by the unsuitability of sites. A conservative approach is adopted for the likely success of geothermal. Aside from a small demonstration project at 10 MW in 2013, geothermal is assumed not to become available on a large scale until 2015 and is constrained to 12,000 MW by 2050.

2.4.4 Technology Costs and Availability

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

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

Carbon capture ready gas and coal plants were also considered, with carbon capture and storage technology not available until 2020[9].

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

Costs for renewable generation projects are derived from published sources of information. MMA maintains a database of renewable energy projects, which contains information on capacity, generation levels, operating costs, capital costs and other costs for each renewable generation project - operating, committed or planned. The location by sub-state region is also known, and incorporated into the model.

Real capital costs for all technologies are assumed to fall over time. A "capital cost reduction factor" is included for each technology in the analysis to model this effect, with the reduction factor specific to the technologies. Capital cost reductions for thermal plant are given in Table 2-1. For renewable technologies, the Federal Treasury provided additional renewable capital cost reduction factors. These were derived from the international modelling with GTEM and were imposed to capture greater learning by doing from greater international deployment of renewable technologies under international carbon policies.

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

Future transmission and distribution prices are estimated from historical trends in prices and recent regulatory decisions on allowable movements in prices (under the CPI-X

9 In the scenario modelled, this technology was not used until well after 2020.

provisions). Network charges were assumed to increase by 5% real per annum until 2019, with this rate declining by 1% per annum until 2024 and then held constant.

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

2.4.5 Fuel prices

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

Key feature of the assumptions are:

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

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

Figure 2-3: Trends in city node gas prices for base load gas demand

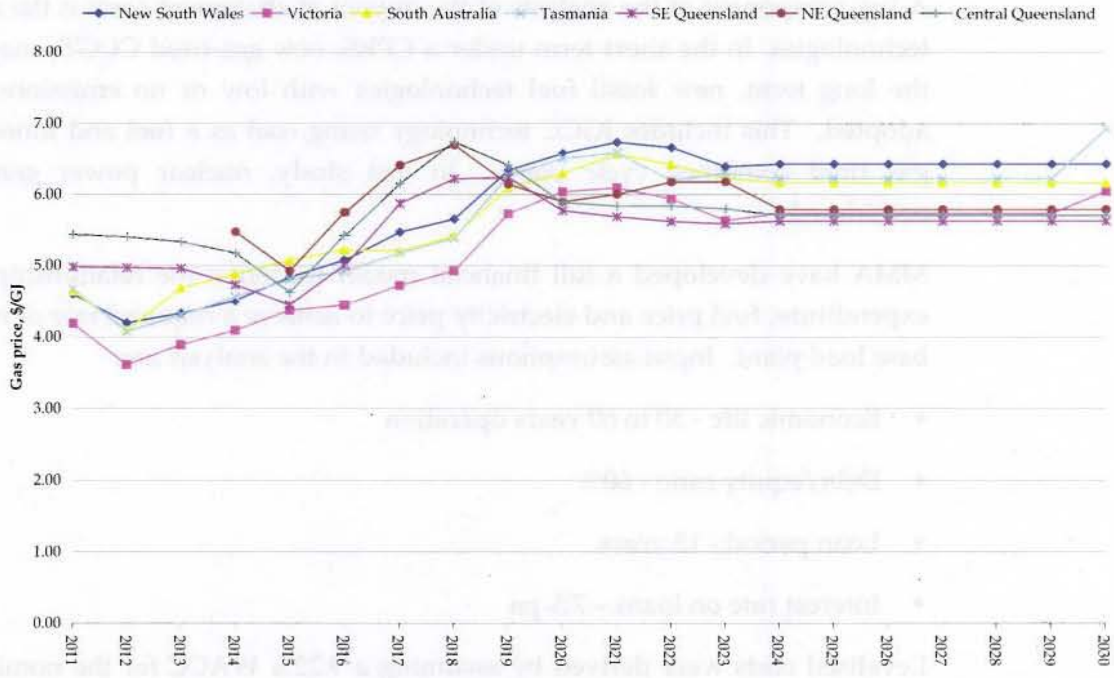
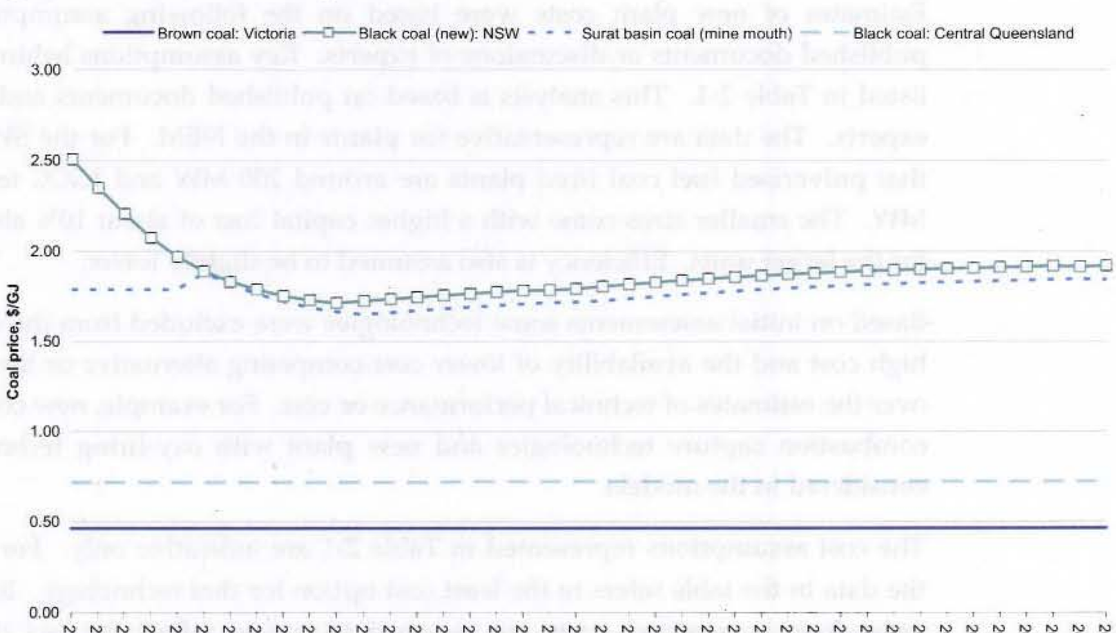


Figure 2-4: Trends in coal prices



2.4.6 Emissions

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

2.4.7 Cost of abatement technologies

A key component of the analysis of the impact of abatement costs is the cost of abatement technologies. In the short term under a CPRS, new gas-fired CCGTs may be adopted. In the long term, new fossil fuel technologies with low or no emissions are likely to be adopted. This includes IGCC technology using coal as a fuel and more efficient natural gas fired combined cycle plant. In this study, nuclear power generation was not considered.

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

- Economic life - 30 to 60 years operation
- Debt/equity ratio - 60%
- Loan period - 15 years
- Interest rate on loans – 7% pa

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

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

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

The cost assumptions represented in Table 2-1 are indicative only. For each technology, the data in the table refers to the least cost option for that technology. But as more of that technology is required, costs are assumed to rise to reflect the fact that the least cost options for each technology is likely to be adopted first. Thus, for example, as more black coal plant are required, the long-run marginal cost are likely to increase as more expensive coal sources are used and as transmission costs to service the market are increased.

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

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

	Life	Sent-out Capacity	Capital Cost, 2010	Capital Cost Deescalater, 2010 to 2020	Capital Cost Deescalater, 2021 to 2030	Heat Rate at Maximum Capacity	Efficiency improvement	Variable Non-Fuel Operating Cost	Fixed Operating Cost
Option	Years	MW	$/kW so	% pa	% pa	GJ/MWh	% pa	$/MWh	$/kW
IDGCC with CCS	30	380	3,026	1.5	0.5	10.4	1.30	5	70
Natural gas options									
CCGT - small	30	235	1,467	0.5	0.5	7.4	0.60	3	22
CCGT - small	30	47	2,054	0.5	0.5	7.8	0.60	4	25
CCGT - large	30	490	1,334	0.5	0.5	6.8	0.60	3	20
Cogeneration	30	235	1,740	0.5	0.5	5.0	0.60	3	20
CCGT with CCS	30	450	2,001	1.0	0.5	7.9	0.70	4	40
Renewable energy options									
Wind	25	99	2,134	0.5	0.5		0.20	2	35
Biomass - Steam	30	28	2,598	0.5	0.5	11.5	0.10	4	50
Biomass - Gasification	25	27	2,784	1.5	1.0	11.0	0.10	5	50
Concentrated Solar thermal plant	20	99	4,176	1.5	1.0				50
Geothermal - Hot Dry Rocks	25	45	4,400	1.5	0.5	12.0	0.10	3	70
Concentrating PV	30	97	4,640	1.0	1.0		0.10		
Hydro	35	30	2,320	1.0	0.5	3.6	0.05	3	35

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

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

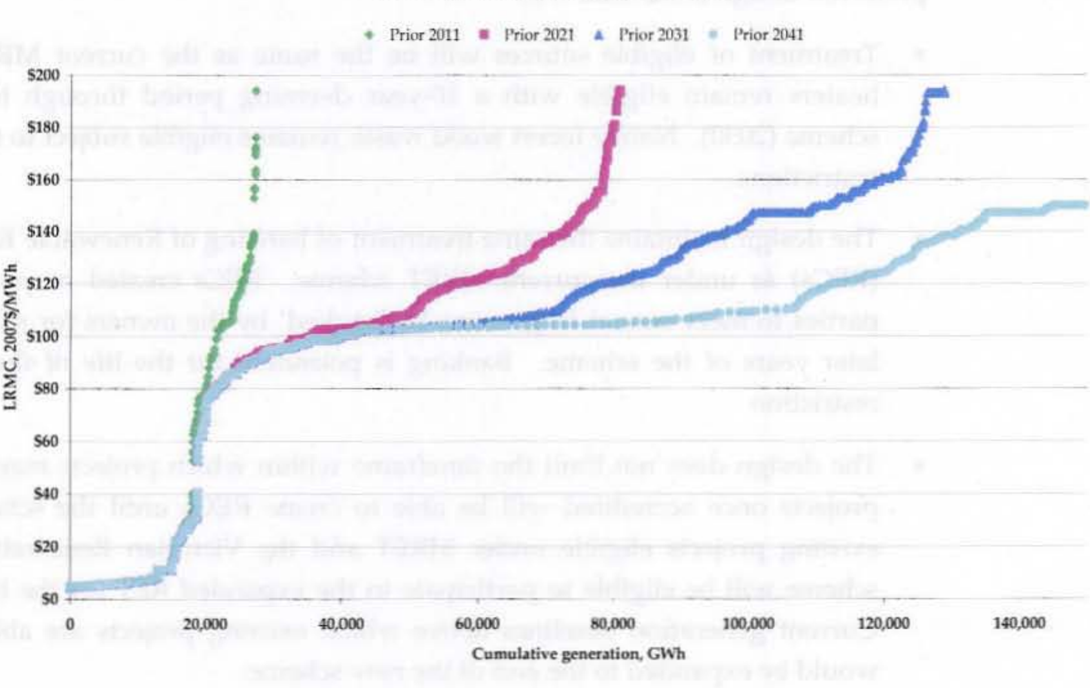
2.4.8 New generation costs – renewable generation

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

The total amount of commercially accessible new renewable generation resource was limited to 130,000 GWh and 185,000 GWh above current levels by 2030 and 2050 respectively. The limitations on new renewable capacity were based upon previous analysis undertaken by MMA and take into consideration system constraints in absorbing intermittent technology such as wind. A conservative constraint on the success on geothermal was employed, with the total capacity restricted to approximately 12,000 MW by 2050.

As with fossil fuel technologies, the long-run marginal cost of renewable energy generation increases as more of each technology is required. For example, less windy sites will be accessed as more wind generation is required. Fuel costs will increase as more biomass options are required. Assumptions on the marginal cost curve as a function of level of generation required are shown in Figure 2-5.

Figure 2-5: Long-run marginal cost for renewable energy generation in Australia



2.5 Scheme Coverage and Scenarios

To model the impact of the expanded RET, two scenarios were constructed as follows:

- **Reference scenario**: CPRS -5 target is implemented but the expanded RET target is not implemented. The current MRET scheme and the Victorian Renewable Energy Target Scheme continue as planned. The carbon price path trajectory rises from \$20/t CO_2e in 2010/11 to \$34/t CO_2e in 2020, \$51/t CO_2e in 2030 and ultimately to \$114/t CO_2e in 2050. The assumptions underpinning the CPRS are those used by MMA in the modelling of emissions trading undertaken for the Federal Treasury[10]. Reference scenario was used as the reference with which to compare the impacts of the expanded RET target.

- **Expanded RETS, Preferred design scenario:** the RET target expands in dual linear fashion to 45,000 GWh in 2020. The scheme ends in 2030. Solar water heaters remain eligible throughout the life of scheme. Generators eligible to earn certificates under the current MRET and VRET schemes and which started created certificates before January 2008 remain eligible until the end of the scheme. There are no limits on banking.

The Federal Government has recently released an exposure draft of the legislation underpinning the expanded RET scheme. The Government has chosen a scheme design that is an amalgam of the three designs proposed in the discussion paper. Elements of the preferred design are as follows:

- Treatment of eligible sources will be the same as the current MRET. Solar water heaters remain eligible with a 10-year deeming period through to the end of the scheme (2030). Native forest wood waste remains eligible subject to the current MRET restrictions.

- The design maintains the same treatment of banking of Renewable Energy Certificates (RECs) as under the current MRET scheme. RECs created or purchased by liable parties to meet annual targets can be 'banked' by the owners for sale or surrender in later years of the scheme. Banking is permitted for the life of the scheme without restriction

- The design does not limit the timeframe within which projects may create RECs. All projects once accredited will be able to create RECs until the scheme expires. All existing projects eligible under MRET and the Victorian Renewable Energy Target scheme will be eligible to participate in the expanded RET for the life of the scheme. Current generation baselines above which existing projects are able to create RECs would be expanded to the end of the new scheme.

- The design includes a fixed (un-indexed) shortfall charge or penalty for non compliance to be set at a level marginally above the projected peak REC price.

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10 See MMA (2008), *Impacts of the Carbon Pollution Reduction Scheme on Australia's Electricity Markets*, report to Federal Treasury, 11 December.

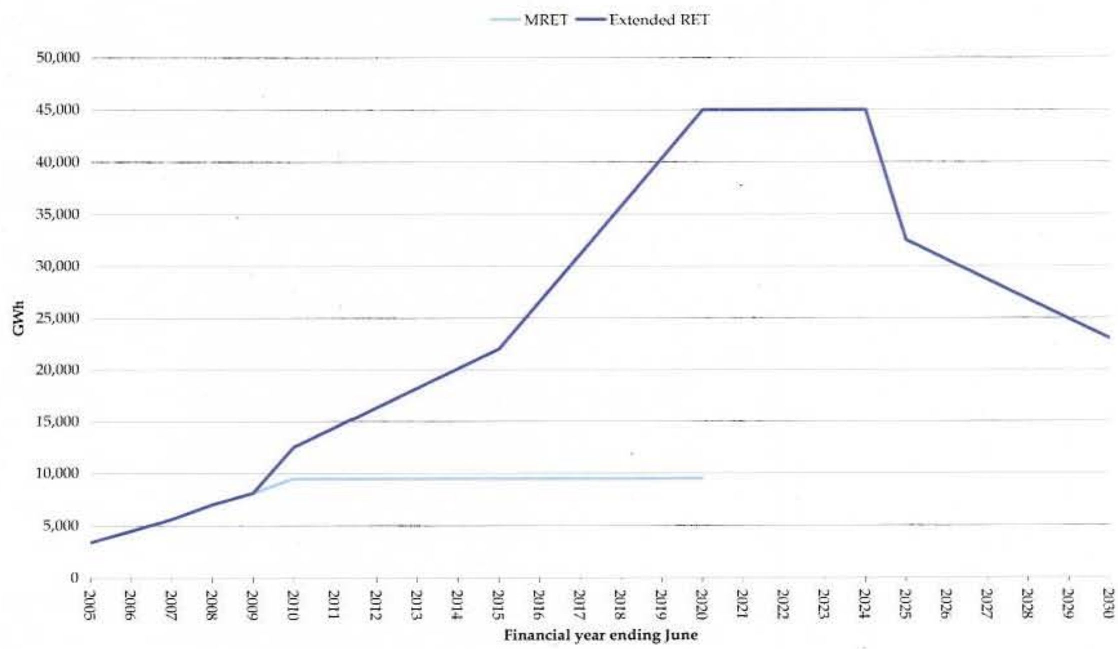
- Multiple RECs can be earnt by small scale generation units from 2009-2010 to 2014-2015 according to Table 2-2. The design includes a multiplier to be applied for RECs created by micro-generation units (including rooftop solar PV systems, small wind turbine systems and micro-hydro systems). For each micro generation system, the multiplier would apply only to the first 1.5 kilowatts of system capacity.

Table 2-2: Multiplier for certificates for small generation units

Item	Period during which system installed	Number of RECs per MWh of Generation
1	1 July 2009 to 30 June 2010	5
2	1 July 2010 to 30 June 2011	5
3	1 July 2011 to 30 June 2012	5
4	1 July 2012 to 30 June 2013	4
5	1 July 2013 to 30 June 2014	3
6	1 July 2014 to 30 June 2015	2

In this report, we assumed that this expanded target will proceed with the targets to the ultimate 45,000 GWh target in 2020 as shown in Figure 2-6 below. It was also assumed that the expanded MRET target would displace the State based renewable energy target as well as the existing Federal MRET target.

Figure 2-6: Expanded RET target



Source: Department of Climate Change.

The preferred design scenario modelled here differs in a number of ways from the policy settings assumed for the RET in the Federal Treasury modelling (which was undertaken before the preferred design was settled and was an amalgam of the options set out by the Working Group). Key differences include the end date is earlier in this study (2030 instead of 2035 in the Treasury simulation) and renewable generators earning certificates under the current MRET scheme remain eligible to the end of the scheme in this study (instead of until 2020 in the Treasury simulation).

3 ELECTRICITY MARKET IMPACTS

3.1 Renewable Energy Generation

3.1.1 Level of generation

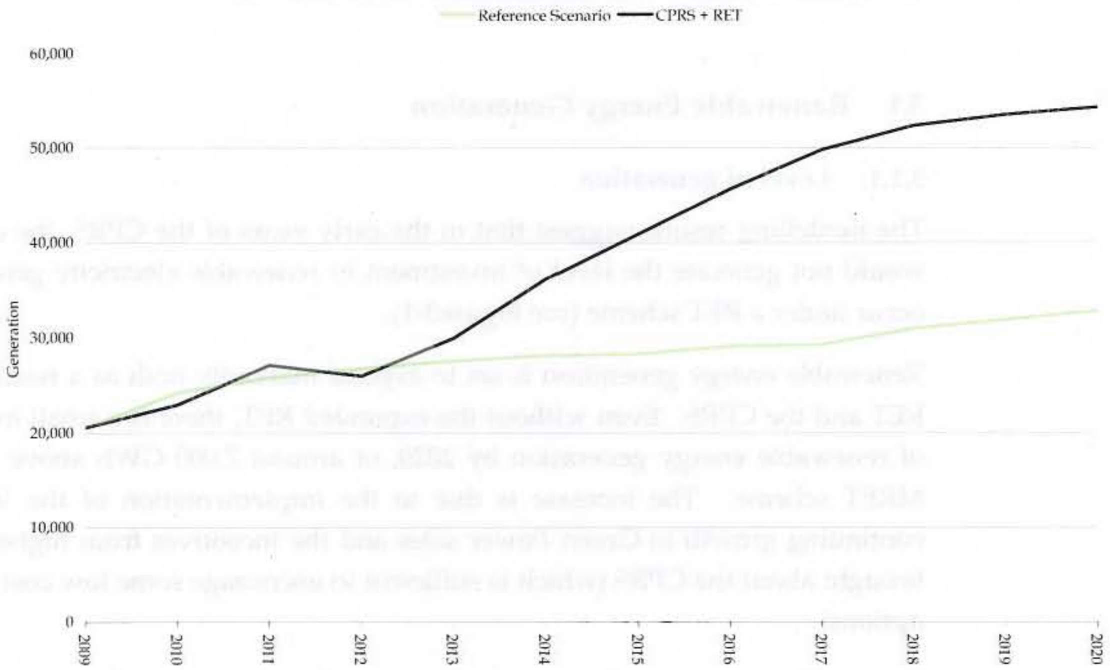
The modelling results suggest that in the early years of the CPRS, the carbon price alone would not generate the level of investment in renewable electricity generation that could occur under a RET scheme (see Figure3-1).

Renewable energy generation is set to expand markedly both as a result of the expanded RET and the CPRS. Even without the expanded RET, there is a small increase in the level of renewable energy generation by 2020, of around 7,000 GWh above under the current MRET scheme. The increase is due to the implementation of the VRET scheme, the continuing growth in Green Power sales and the incentives from higher electricity prices brought about the CPRS (which is sufficient to encourage some low cost renewable energy options).

Renewable generation, however, effectively doubles under the expanded RET scheme. Generation from eligible renewable energy generation sources increases three-fold under the scheme. Although renewable energy generation increases in all States, the bulk of the increase occurs in NSW and Victoria. South Australia only experiences a modest increase despite its good wind resource, as higher levels of renewable energy generation in that state are likely to cause wholesale market prices to fall. The level of renewable energy generation in Western Australia also increases but is constrained by the limited amount of wind capacity the system can handle and the inability to transport excess renewable energy generation to other markets. Renewable energy generation in Tasmania is similarly limited by the amount of power that can be exported to the mainland. There is no increase in renewable energy generation in the Northern Territory prior to 2020, but there is some investment in solar thermal generation in the following decade.

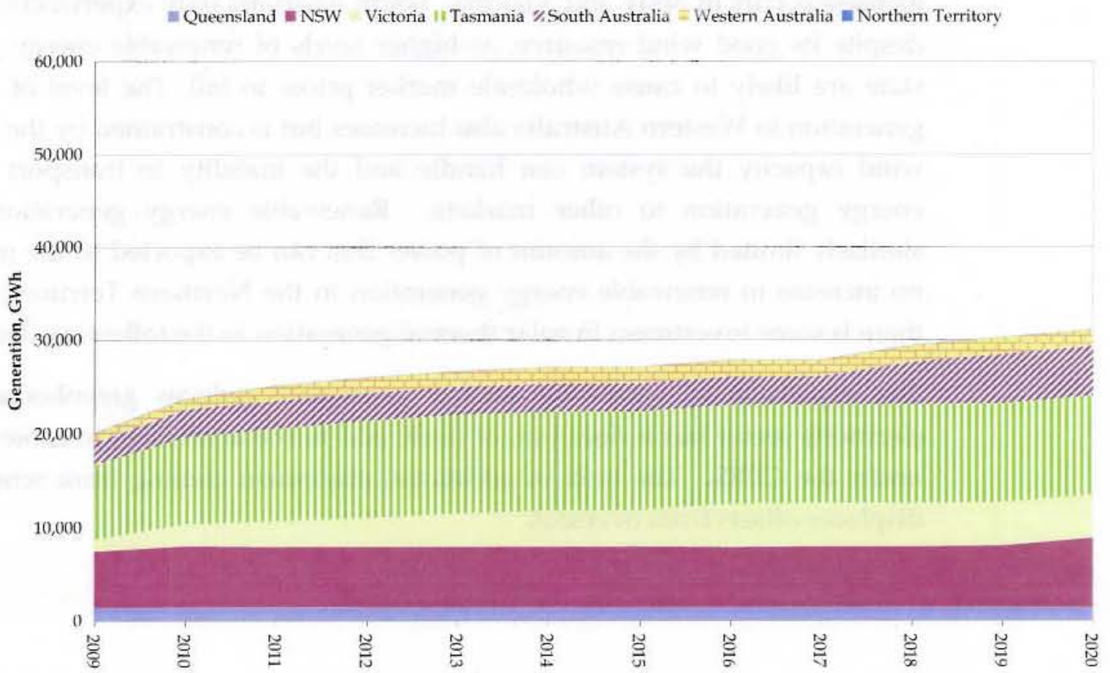
The expansion of renewable energy generation reduces greenhouse gases from the electricity sector but it does not, of itself, add to the abatement to achieve the fixed target under the CPRS. The bulk of additional abatement coming from renewable generation displaces offsets from overseas.

Figure3-1: Total renewable energy generation in Australia



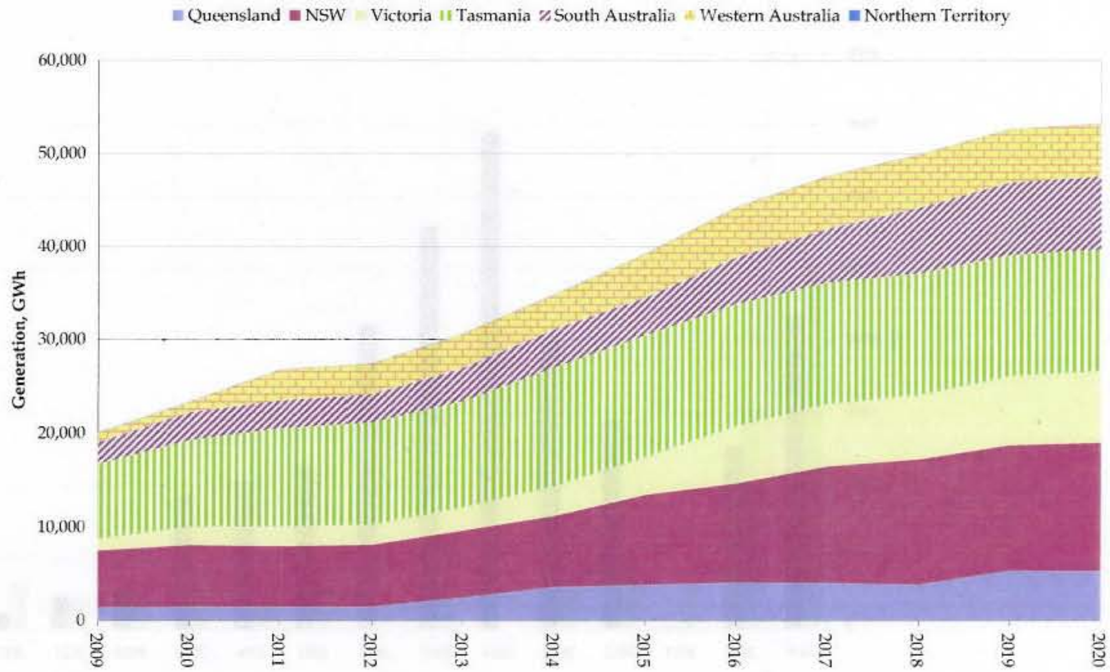
Note: Includes a provision for the annual generation from solar water heaters and deemed generators

Figure 3-2: Renewable energy generation by State, reference scenario



Note: excludes small scale PV and solar water heater generation and eligible generation not supplying the major grids (NEM, SWIS and DKIS).

Figure 3-3: Renewable Energy Generation by State, CPRS plus Expanded RET



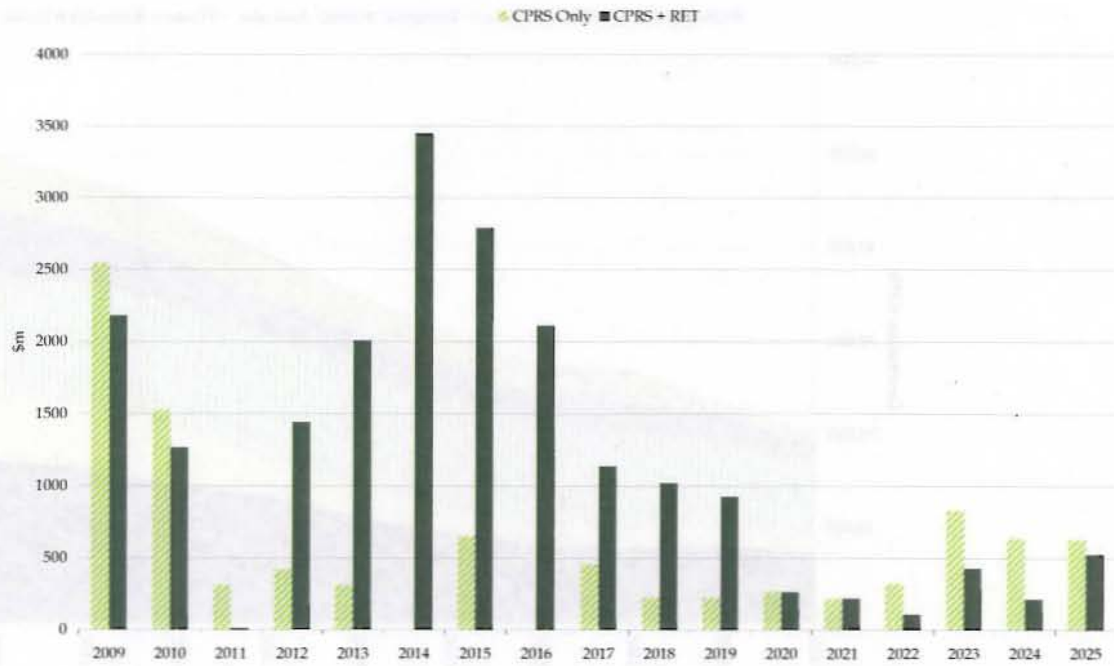
Note: excludes small scale PV and solar water heater generation and eligible generation not supplying the major grids (NEM, SWIS and DKIS).

3.1.2 Investment profile

All generation technologies expand, but over 70% of the increase comprises additional wind generation and new geothermal (hot dry rocks) generation. Increased biomass and expansions at existing hydro-electric (as well as some mini-hydro facilities) also occur but growth in these technologies is limited either by their high cost or their limited opportunities.

Investment is spread over the period to 2020, but there tends to be a higher level of investment around the period 2013 to 2017. Investment in the period to 2020 is estimated to be around $19 billion in total, with a present value of around $12 billion (assuming an 8% discount rate).

Figure 3-4: Investment in renewable energy capacity with expanded RET



Investment continues to increase after 2020, as carbon prices continue to dominate investment decisions in renewable generation, without the need for an expanded RET. The expanded RET helps to support the renewable energy industry in the years before the carbon price is high enough to make them competitive. The modelling shows that once the carbon price reaches a level at which it strongly influences investment decisions, the effects of the RET scheme will phase out naturally, reflected in the decline of the price of RECs. Consequently the phase out design for the RET does not impact materially on the scheme as long as the carbon price is sufficiently high at the time of phase out.

This implies that the major impact of the expanded RET is to bring forward investment in renewable generation. In the absence of the RET scheme, the same level of investment in renewable energy generation would not occur until 2035 in the reference scenario. The RET therefore brings forward investment in renewable generation that would eventually occur over a longer time frame, or with higher carbon prices.

3.1.3 Technology mix

As the expanded RET acts to push renewable generation into the electricity market faster than would have occurred under the CPRS, the technologies captured by the RET primarily favour those that are market-ready, such as wind and biomass. By 2020, almost half the extra renewable generation induced by the RET is taken up by wind generation.

Geothermal generation is also projected to contribute strongly to the RET target. However, due to its infancy, it does not come into the market until the latter stages of the scheme. Small amounts of geothermal generation come online between 2012 and 2015, and substantial capacity ramps up from 2016, increasing to around 10,000 GWh by 2020 (equivalent to one fifth of the target).

Biomass generation also contributes significantly to achieving the 45,000 GWh target. The additional biomass generation is encouraged in the early years of the scheme as a relatively cheap form of generation. Almost half the additional biomass generation is established in Queensland, mainly consisting of bagasse generation. New South Wales and Victoria are also projected to increase investment in biomass generation.

A small amount of additional investment is also projected in hydro electric generation. These additional investments are mainly in the form of upgrades of existing generation facilities, as opposed to the development of new hydro-electric sites.

Solar water heaters currently contribute up to 30 per cent of the target under the current MRET scheme. While the uptake of solar water heaters is projected to increase over time under the expanded RET scheme, their proportion of the REC market declines as the target increases. By 2020, they are projected to contribute around 8 per cent of the REC market.

3.1.4 State Impacts

Figure 3-5 shows the projected uptake of renewable investment by state. The majority of additional investment induced by the RET occurs in Western Australia, Queensland and NSW, 18 per cent, 18 per cent and 28 per cent respectively (mostly biomass and geothermal in Queensland and wind, geothermal and biomass in New South Wales, wind and biomass and wind in Western Australia). Victoria also has a high uptake, particularly in wind generation, although the proportional increase in renewable generation in Victoria is greater than implied as there is an increase in renewable generation in that state in the reference case due to VRET. South Australia accounts for 11 per cent, again mostly wind and geothermal technologies. Tasmania accounts for 11 per cent of the increase, mainly through additional wind generation and some upgrades of existing hydro-electric facilities and additional biomass projects.

Figure 3-5: Renewable energy generation by State, additional to the CPRS due to expanded RET

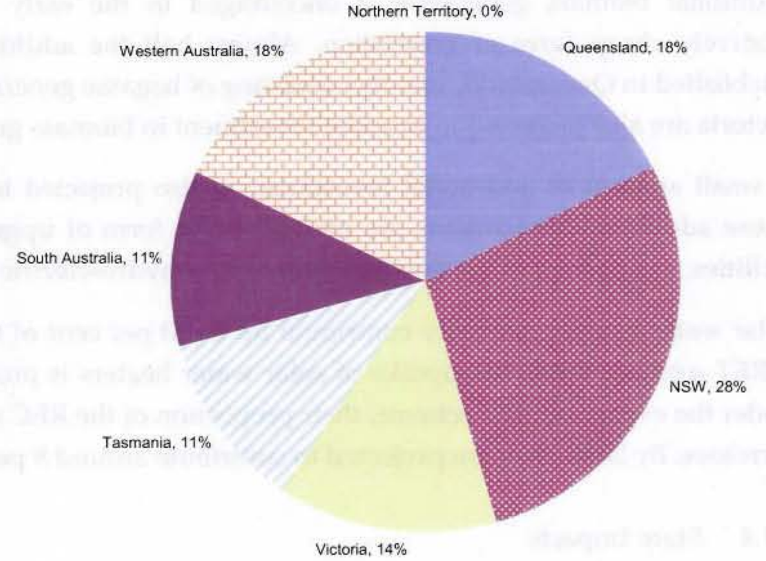
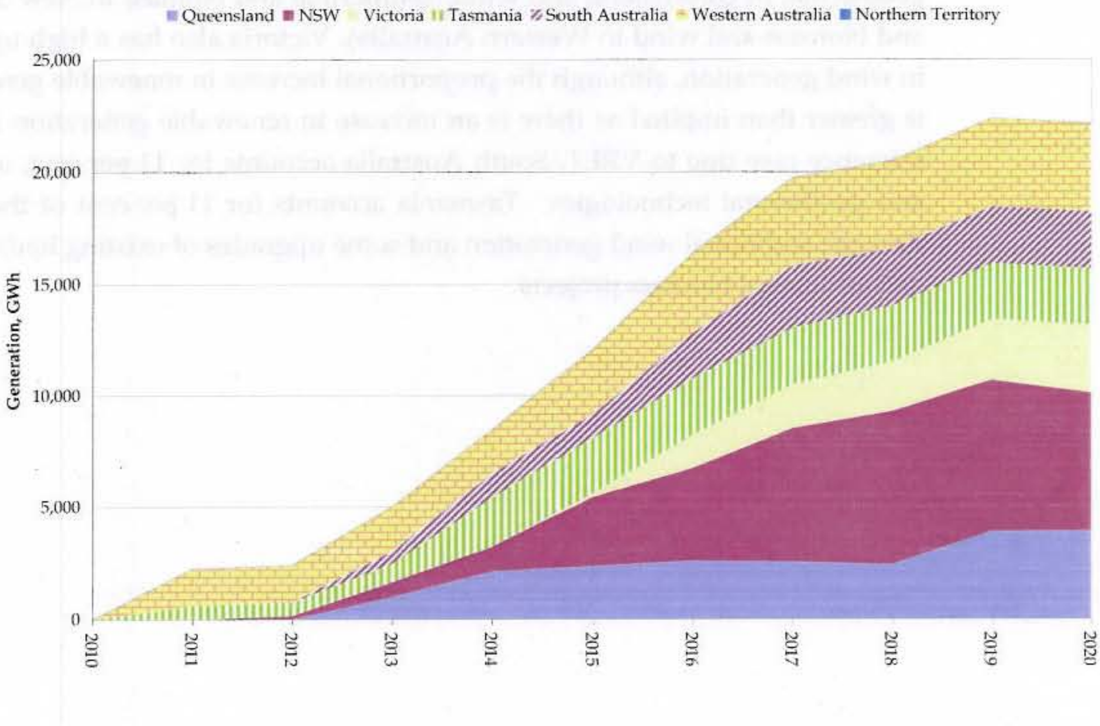


Figure 3-6: Additional renewable energy generation due to expanded RET



3.1.5 REC prices

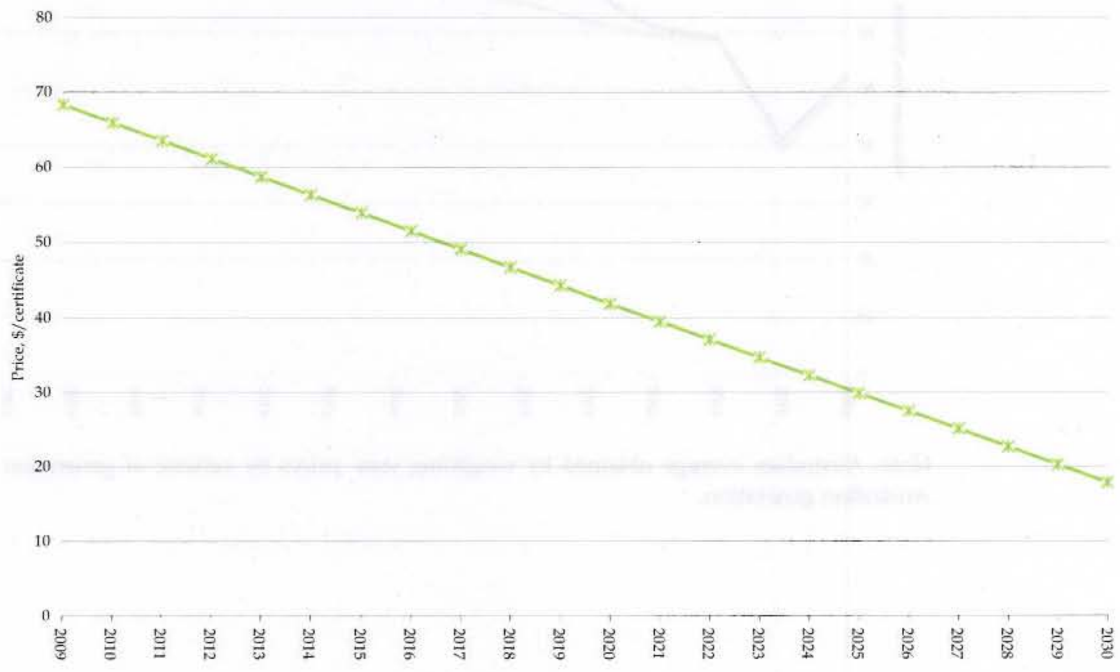
Certificate prices are shown in Figure 3-7. The price in each year reflects long term contract prices for certificates that are required to support the renewable energy generation that enter the market in each year. Each year's certificate price reflects the prices a renewable generator could obtain under long term contract in the year of entry into the market.

Prices are set to ensure all renewable generators that enter the market recover their costs including return to capital over their economic life. That is, the certificate price is set in such a way that the marginal plant coming into the market earns enough from electricity market and certificate transactions to recover the long run marginal cost of generation.

Under the expanded RET scheme, prices start off at around $70/MWh and then decrease over time. The high initial price occurs because this is the price required to get the additional renewable generation in the early years of the scheme when the outlook is for decreasing certificate prices over time. Electricity prices are also expected to increase slowly over time, so that the revenue required under the RET to recover investment costs decreases over time. This is partly offset by the increasing cost of renewable energy as the target increases, but this cost increases at a slower rate than the price of electricity.

Prices are also high initially as new plant entering before 2020 have limited opportunity to recover their costs as existing renewable energy plant (eligible to earn certificates under the existing MRET scheme) still can take a large portion of the certificate market even when the target is decreasing from 2025 onwards. This reduces the opportunities for new plant to recover their costs through certificate prices.

Figure 3-7: Certificate prices under the expanded RET Scheme



3.2 Electricity Markets

3.2.1 Wholesale Prices

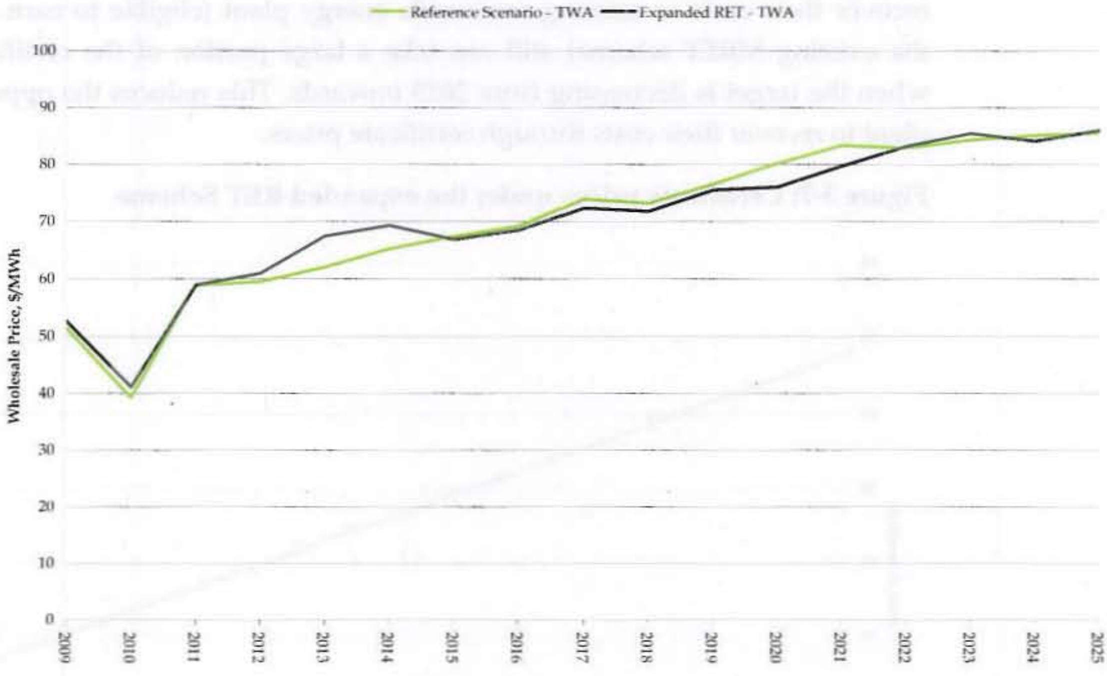
The expanded RET scheme has a modest impact on wholesale electricity prices. Wholesale electricity prices for the period 2010 to 2020 average $66/MWh for the Reference scenario. The difference in price with the expanded RET is -5% to 8% over the entire period, with an average increase of 0.5%. The impact of RET is limited in these scenarios as additional renewable generation is matched by deferment of fossil fuel generation capacity and some additional retirement of existing plant. Additional volatility caused by the variable patterns of wind generation also increase prices.

Table 3-1: Impact of expanded RET on wholesale prices, Australia

	2010 -2015	2016 -2020	2021-2025
TWA Price, reference scenario, $/MWh	59	75	84
TWA Price, expanded RET, $/MWh	61	73	84
% change due to expanded RET	3.5	-2.4	-0.6

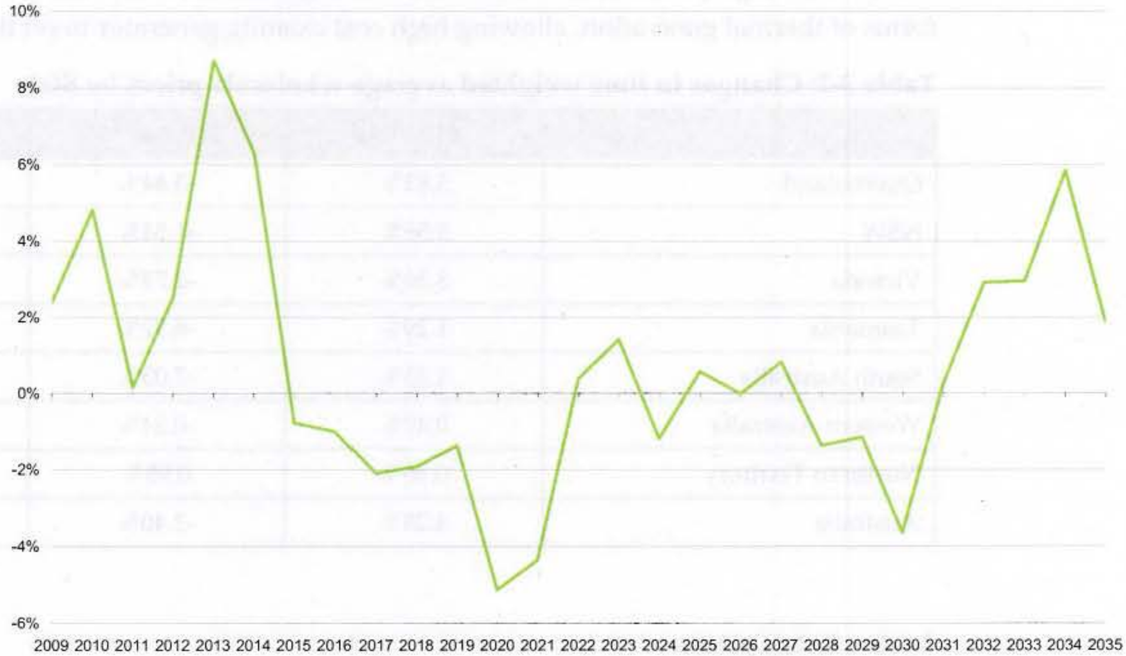
Note: time-weighted average prices across all regions in Australia. Regional prices weighted by the volume of generation in each region.

Figure 3-8: Average wholesale prices (NEM, SWIS, DKIS), time weighted average



Note: Australian average obtained by weighting state prices by volume of generation in that state to total Australian generation.

Figure 3-9: Change in wholesale price of electricity, time weighted average across all regions



Combining the wholesale price and certificate prices sees renewable generators earning an expected price in the vicinity of $105/MWh to $125/MWh.

Figure 3-10: Combined time weighted average price and certificate price

Victoria and New South Wales exhibit the largest increase in prices in the period to 2020. Tasmania and South Australia experience a decrease in prices over the period to 2020 (with price decreases in the period after 2015 compensating for a small increase in price in the period prior to 2015). Relatively high price increases occur in NSW and Victoria due to the fact that high penetration of new renewable generation deters entry for other low cost forms of thermal generation, allowing high cost existing generator to set the price.

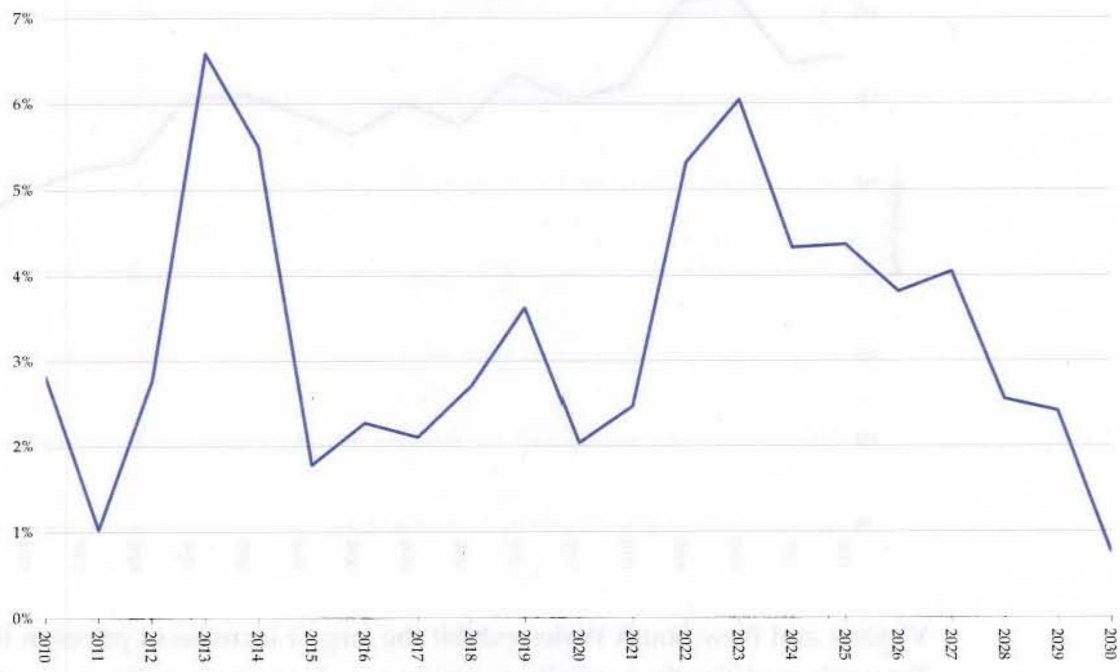
Table 3-2: Changes in time weighted average wholesale prices by State

	2010 -2015	2016 -2020	2021-2025
Queensland	3.82%	-3.44%	-0.51%
NSW	5.56%	-1.34%	1.63%
Victoria	3.54%	-2.73%	-0.21%
Tasmania	1.29%	-6.32%	0.04%
South Australia	1.33%	-7.03%	-4.03%
Western Australia	0.42%	-0.24%	-4.53%
Northern Territory	0.48%	0.95%	-0.71%
Australia	4.25%	-2.40%	-0.54%

3.2.2 Retail prices

Retail prices, however, are expected to increase by around 3.0% in the period to 2020 and 3.7% in the period from 2021 to 2030. The increase is due to the added cost of purchasing certificates, which can add up to $4/MWh to retail prices in the period to 2020, and around $6/MWh in the period after 2020.

Figure 3-11: Change in average retail prices, CPRS + RET versus Reference scenario, Australia, %



The percentage change varies considerably from year to year due to variations in the changes in the underlying wholesale prices as affected by changes in the pattern and timing of entry of new fossil fuel plant. With the expanded RET scheme, the profile of investment in new fossil fuel plant changes and this can change the pattern of wholesale prices from year to year (creating temporary surpluses or deficits of conventional generation relative to the reference scenario). Thus, the price increase in 2013 for example is due to a large increase in the wholesale price as the expanded RET defers the need for new fossil fuel plant in that year, in combination with higher retail imposts due to the increasing target. Annual fluctuations in price should be interpreted with caution as regards to the impact of the expanded RET scheme, as the annual fluctuations could reflect an assumption of highly rational behaviour in the timing of entry of new fossil fuel plant rather than the impact of the expanded RET scheme.

Table 3-3: Change in retail prices due to expanded RET, by State

	2010-2020	2021-2030
Change from Reference scenario case, $/MWh		
Queensland	5	7
NSW	6	8
Victoria	5	5
Tasmania	3	5
South Australia	2	4
Western Australia	-4	2
Northern Territory	4	7
Australia	4	6
% Change from Reference scenario case		
Queensland	4%	4%
NSW	5%	5%
Victoria	4%	3%
Tasmania	2%	3%
South Australia	2%	3%
Western Australia	-3%	1%
Northern Territory	3%	5%
Australia	3%	4%

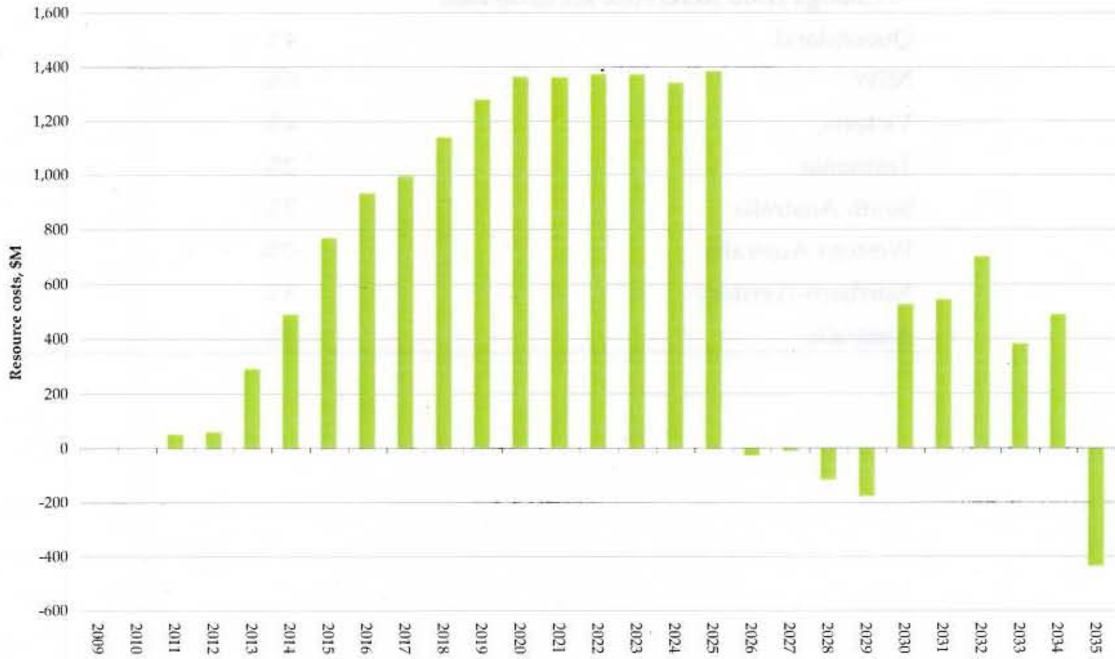
4 COST AND BENEFITS THE ECONOMY

4.1 Costs to the generation sector

Renewable energy is, on average, more expensive per megawatt hour than conventional fossil fuel based generation. Even with carbon prices imposed, renewable energy generation is likely to be more expensive. Dedicating a wedge of the generation mix to a more expensive technology means that more capital, fuel and operating resources are now required to supply a given level of electricity. Furthermore, because electricity is now more expensive, less electricity is likely to be demanded at the expense of more of other substitutable inputs. However, this impact is likely to be minimal because of the inelastic response of demand to small changes in price. The resource cost calculated in this study represents the cost of renewable energy generation less the avoided cost of conventional generation.

The resource cost of generating electricity includes capital, fuel, labour and material costs. Additional resource costs come from higher capital and, potentially, operating costs. This will be offset to some degree by lower fuel costs for conventional generation. Additional expenditure on renewable energy amounts to $16 billion in the period to 2030. In present value terms (assuming a discount rate of 8%), the additional expenditure amounts to $6 billion. The estimates of resource costs represent about 7% of the present value of the total cost of resources used in electricity generation.

Figure 4-1: Additional resource costs in electricity generation



The analysis did not include any reduction in the cost of renewable energy generation over time brought about the expanded RET through learning by doing.

4.2 Costs to the economy

GNP is reduced by around than $177 million per annum as a result of the expanded RET. The present value of the change in GNP is in Table 4-1, and indicates a cost to the economy of around $2 billion to $3 billion. This reduction represents a reduction in GNP of around 0.01 per cent.

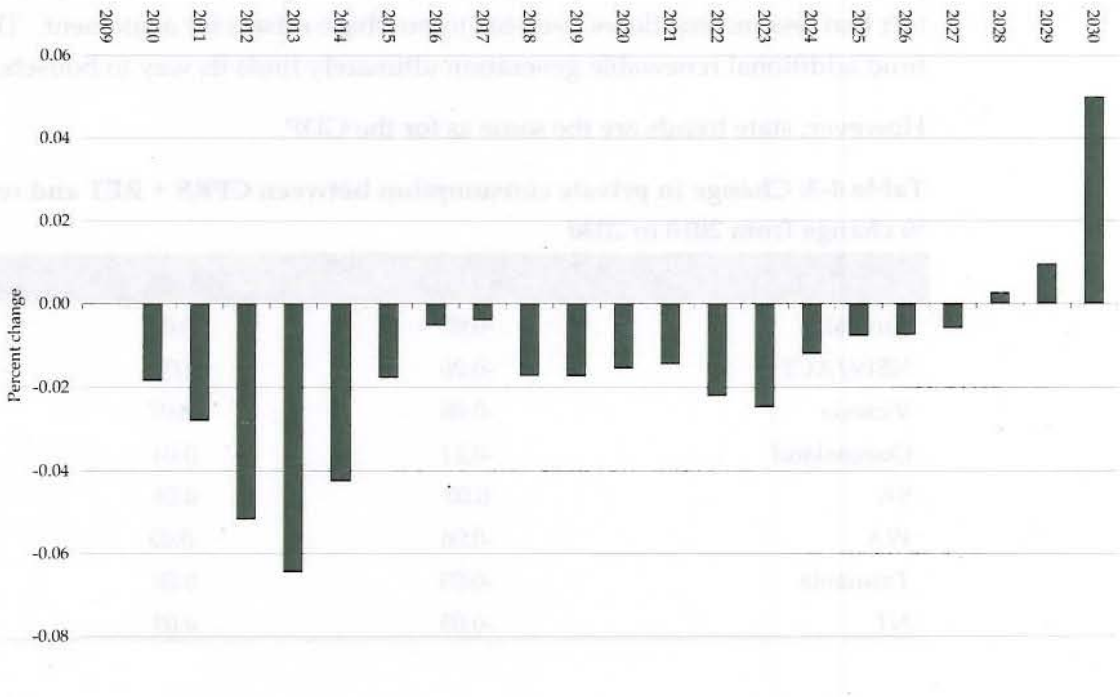
Table 4-1: GNP difference between expanded RET and reference scenario

Item	Value
Present value of difference, $million	-2,418
% Difference	0.01%

Calculated using a 8% discount rate over the period to 2030

GNP improves towards 2030. This occurs because under the incentive structure of the expanded RET scheme, the costs of the scheme tend to be allocated more to the early and middle years of the scheme. From 2025, most of the costs to the economy (borne through certificate prices and the compliance target) start to disappear as the target reduces and the certificate price falls, but the renewable generation engendered is still generating at low short run marginal cost. Further, the additional renewable generation displaces purchases of emission abatement permits from overseas, increasing the circulation of income in the domestic economy.

Figure 4-2: Change in GNP relative to reference scenario[11], %



[11] Based on the difference in GNP with and without expanded RET scenario.

GDP impacts for Australia and the States are compared in Table 4-2[12]. The impacts depend on two offsetting impacts: the increase in energy prices and deferment in fossil fuel investment (which reduces GDP) and the level of investment in renewable energy (which can add to GDP). The average national impact is around 0.03 per cent of GDP. The largest impact is a reduction of 0.10 per cent of Gross State Product in Victoria, due to the impact on energy costs plus deferment in new capacity. The 0.08 per cent decrease in the Northern Territory occurs because of high energy costs only (as no new renewable investment occurs in that state prior to 2020). Tasmania exhibits a small benefit due to the investment of new wind capacity.

Table 4-2: Change in GDP between CPRS + RET and Reference scenario, % change from 2010 to 2030

	Present value of change to GDP, $ million	% change in GDP
Australia	-5,796	-0.04
NSW/ACT	-1785	-0.04
Victoria	-3,222	-0.10
Queensland	-543	-0.01
SA	406	0.04
WA	-1,087	-0.07
Tasmania	580	0.28
NT	-126	-0.08

Impacts on private consumption are compared in Table 4-3. Private consumption decreases less than does GDP as a result of the expanded MRET. This is largely due to the fact that less income flows overseas to purchase offsets for abatement. The income used to fund additional renewable generation ultimately finds its way to households.

However, state trends are the same as for the GDP.

Table 4-3: Change in private consumption between CPRS + RET and reference scenario, % change from 2010 to 2030

	2010-2020	2020-2030	2010-2030
Australia	-0.07	-0.01	-0.04
NSW/ACT	-0.06	0.01	-0.03
Victoria	-0.08	-0.07	-0.08
Queensland	-0.11	0.04	-0.04
SA	0.00	0.05	0.02
WA	-0.06	-0.03	-0.05
Tasmania	-0.03	0.08	0.02
NT	-0.03	0.03	-0.01

12 Note: The discussion is on GDP here rather than GNP as State based GNP results are not estimated.