Final Report to
MRET Review Panel

Impacts of a 20,000 GWh Target for the MRET Scheme

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ERRATA

Page 29, second paragraph:

> First line – delete '$32.9' and insert '$22.0'.
>
> Second line – delete '$22.9' and insert '$31.6'.

Page 32, section 3.8, first paragraph:

> First line – delete 'with the current MRET target' and insert 'to no MRET'.
>
> Second line – delete 'impact is less than 0.08% of GDP over the time period of the analysis' and insert 'maximum impact in any one year is less than 0.08 % of GDP over the period of the analysis'.

Page 32, table 3.7, title:

> Delete 'current MRET target' and insert 'no MRET'.

Page 32, section 3.8, second paragraph:

> Fourth line – delete 'unindexed' and insert 'indexed'.

Page 43, first paragraph:

> Fourth line – delete '$2.03/MWh' and insert '$1.81/MWh compared to no MRET over the period from 2003 to 2020'.
>
> Seventh line – delete '$2.50/MWh, an increase of about 23%' and insert '$3.57/MWh compared to no MRET over the period from 2003 to 2020, an increase of about 97%'.

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ABBREVIATIONS

CCGT	Combined Cycle Gas Turbine
COPS	Centre of Policy Studies
GDP	Gross Domestic Product
MMA	McLennan Magasanik Associates
MRET	Mandatory Renewable Energy Target
NEM	National Electricity Market
RECs	Renewable Energy Certificates
SWIS	South West Interconnected System of Western Australia

1 INTRODUCTION

The Mandatory Renewable Energy Target Scheme (MRET) imposes an obligation on electricity retailers and large consumers to purchase a percentage of their power requirements from renewable sources. To facilitate this objective, qualifying renewable energy generators are permitted to create tradable Renewable Energy Certificates (RECs) for each MWh of renewable electricity generated. Electricity retailers and large customers submit a legislated number of RECs in proportion to their electricity purchases in each year of the operation of the scheme.

MRET is currently being reviewed and the purpose of this study is to inform this review of the impacts of changes to the target of renewable generation under the MRET measure. The MRET Review Panel has contracted McLennan Magasanik Associates (MMA) to estimate the impacts on the electricity industry and the wider economy of increasing the target from 9,500 GWh in 2010 with a linear increase to 20,000 GWh in 2020 and then remaining at 20,000 GWh.

Two variations to the shortfall charge were also applied. They were:

- A shortfall charge of $40 through to 2035 not indexed
- A shortfall charge of $40 indexed from 2010

Results of the modelling simulations are discussed in this report.

2 METHODOLOGY AND KEY ASSUMPTIONS

In this section, the methodology used to estimate renewable energy certificate prices and the technology mix, the amount of abatement, the impact on electricity prices and the impact on the wider economy is described.

The energy sector in Australia has undergone substantial restructuring over the past decade. An outcome of the restructuring is that the energy markets in Australia are becoming integrated. Restrictions on interstate trading of electricity have been removed, allowing the development of new electricity systems between States. Factors affecting the electricity markets in one region will impact on the markets in other regions.

Thus, a method to project the impacts of MRET would require modelling of the integrated electricity markets in Australia. The method would need to account for the economic relationship between the electricity and renewable energy markets, the competitive structure of the wholesale markets in electricity and the market for renewable energy certificates.

2.1 Modelling Concept

2.1.1 Financial drivers for renewable generation

Renewable generators earn revenue from the following sources:

- Sale of electricity in the wholesale market.
- Avoidance of network costs and other wholesale market fees. In some cases, renewable generators may be located close to loads. Examples include generators located near small rural townships or roof-top photovoltaics in urban areas. With the close location of the generator, the loads may avoid some network costs.
- Revenue from other services provided. For example, some waste-to-energy generators earn revenue from avoiding landfill charges and from processing recyclable material.

But renewable generators also incur significant costs. Costs of renewable energy generation are usually higher than conventional generation options such as coal or gas-fired plant. The higher costs arise from the immaturity of some technologies and the smaller scale of the plant.

The main cost is the capital cost, which tend to be higher on a per unit output basis than for conventional generation. For biomass projects, fuel cost is also an important cost component. Other costs incurred include transmission connection costs, which can be high in remote regions, ancillary service costs and market fees.

Renewable generators also face a number of other risks, which make it harder for them to compete with conventional generation. These risks include[1]:

- High sponsor risk. The reluctance of customers to enter into long-term contracts for the electricity output increases the risks faced by renewable generators.
- Reliability of supply. Intermittent generation for some renewable technologies means they cannot be relied upon to generate in periods of high prices.
- Fuel supply and aggregation cost. For biomass generators there are uncertainties over the amount of fuel available and its cost.
- Technology risk.
- Large transaction costs. Approval costs and financing costs are the same for small projects as for large projects, tending to increase per unit cost of generation for the small scale renewable projects.

Because of the higher costs, renewable generation would not enter the market without revenue from other sources. The creation and sale of certificates under MRET enables additional revenue to be earnt.

2.1.2 Price formation

The price of renewable certificates is a function of the cost of supply of renewable generation, the level of the generation required to meet the target and the structure of the wholesale market and the market for certificates.

Price formation in a competitive certificates market can be represented by Figure 2.1. The horizontal axis represents the quantity of certificates required in MWh. The vertical axis represents the price of certificates in $/MWh. The quantity, Ti, represents the renewable target in year i. The step curve designated MCi represents the net cost of renewable energy technologies. The net cost is equal to the total cost of the technology levelised over its project life and subtracting revenues received other than from certificates. This revenue may include receipts from transactions in the wholesale electricity market, avoided network costs brought about by embedded renewable energies and revenue from other outputs. Each step represents

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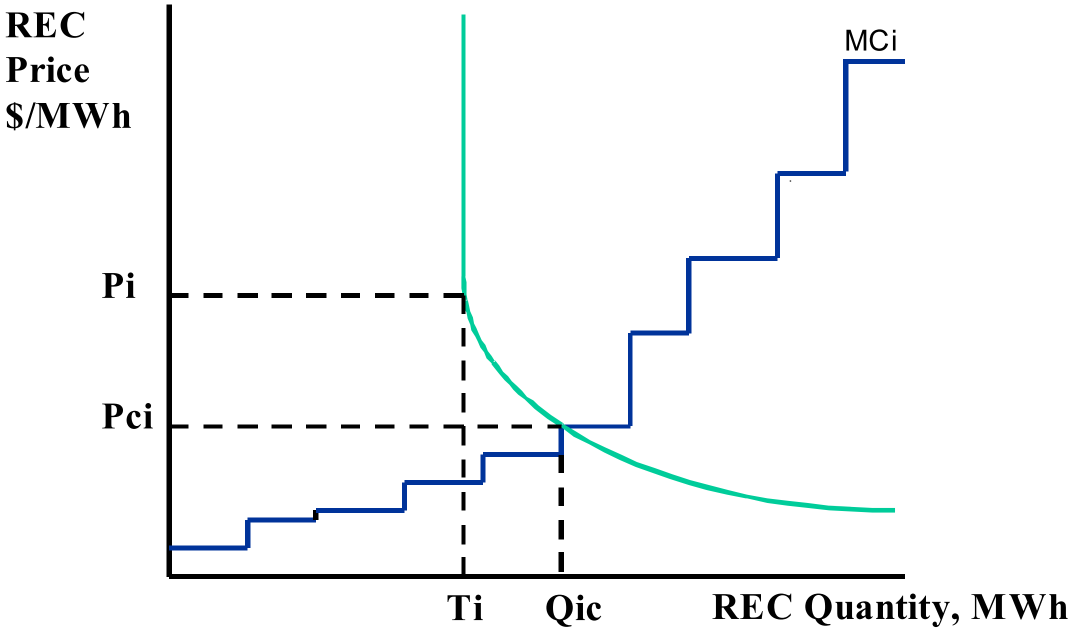
[1] S. Weller (2001), "The importance of the renewable energy certificate market in project economics using a bio-energy project example", paper presented at *The Renewable Energy Market and REC Review for 2002*, Brisbane, 4 -7 December.

the cost of a particular renewable energy source, where the renewable energy source is defined by type of technology and its physical location. The price of the certificates, Pci, is equal to the net cost of the last technology required to meet the specified demand for certificates in year *i*, *Qic*, which is higher that the target level due to the demand for certificates for banking.

Figure 2.1:Price formation for renewable energy certificates



Under a competitive market regime with fully informed participants, the market-clearing price for certificates equates with the long run average cost of the last renewable energy source required to meet the target. A higher price would encourage other higher cost renewable options to enter the market. A lower price would not encourage sufficient renewable generation in the market.

There are a number of important features to the process of price formation.

First, the cost structure for many renewable technologies is characterised by high up-front capital cost but low operating costs. The total cost of renewable technologies is also likely to be higher than the total cost of conventional alternatives over the short to medium term. With these factors, renewable energy generators are unlikely to enter the market unless supported by long-term contracts. This factor is recognized by the decision of the Government to extend the scheme to 2020, allowing for participants to enter into long-term contracts to enable the recouping of costs over that period. Renewable energy suppliers are likely to be interested in entering the market under long term contracts covering all or a substantial part of their output. This carries additional risks for retailers who have to pass on the cost of these contracts to contestable customers.

Second, intra-marginal units receive revenue in excess of their long run average cost. This is a function of the cost curve, which assumes discrete steps in costs, as more renewable energy generation is required. If there is asymmetry of information, with retailers being more informed than individual renewable energy generators, and a lack of competition it is possible that renewable energy generators receive only their long run average cost, with retailers or third parties securing a large part of the surplus on any on-sale of certificates.

Third, it is expected that the cost of renewable energy generation will fall over time. Given that the certificate price is strongly dependent on the cost of renewable generation, it is to be expected that the certificate price would be likely to fall over the long term, all other factors equal. However, the anticipated long-term decline in technology costs may be partly offset by other factors such as limitations on the available renewable fuels and other environmental restrictions on generation options.

2.1.3 Factors affecting price of renewable energy certificates

The Renewable Energy Resource

Renewable energy technologies are generally characterised by a number of features that will ultimately impact on the price of the certificates. Factors affecting the choice of renewable generation options include:

- Constraints on fuel resource availability. These impacts on the costs of biomass generators, 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, solar insolation levels).
- Changes over time in the capital costs of renewable energy technology. The trend has been for declining costs of renewable energy capital costs 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).
- Regulations affecting supply, which will impact on the level and cost of each renewable generation technology. The Renewable Energy (Electricity) Act and associated rules defines eligible sources of renewable

generation and defines restrictions on fuel sources, such as waste wood derived from native forests and plantations.

- Other regulations that impact on the availability of resources, such as environmental and heritage regulations which may affect the amount of renewable generation occurring in some locations.
- Strategic factors that may cause investments in the options that are not the least cost options.

Electricity Prices

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.

Renewable generators will receive revenue in wholesale market transactions in two ways. First, through sales on the spot market which typically involves an auction system where generators are required to bid for the right to dispatch capacity into the market. In spot markets, prices are set by the bid of the last generator dispatched to meet load in each hour. 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.

Second, revenue can be earned either through contract sales with contestable customers or through power purchase agreements with the main supply utility. The value of these sales will be equivalent to the costs foregone from sourcing electricity from renewable generators rather than conventional fossil fuel generators. Most output from renewable generators will be sold under contract.

Factors affecting the value of electricity sales in the wholesale market include:

- Trends in demand, including growth rates in peak demand and energy consumption as well as trends in the profile of demand. In many markets, demand has grown faster in peak and shoulder periods, favouring renewable generators that generate in those periods.
- The balance of supply and demand. In some of the wholesale markets, there is a surplus of generating capacity, which has resulted in low

wholesale market prices. In the long run, supply and demand should be in balance.

- Cost of new generation capacity, which sets the upper bound to pool prices in the long-term under competitive market conditions.
- Regulatory arrangements, which may impact on the price setting in wholesale markets.

Due to the operation of these markets the price of electricity varies 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. As an example of this diurnal cycle, wind profiles indicate increased generation during peak periods resulting in a higher average price for sales than a simple daily average. On the other hand solar hot water systems, where they displace off-peak electric systems, avoid a much lower average electricity price.

Additional Benefits to Generators

For some renewable generators, particularly embedded and distributed generators, other market services can be provided. Examples include ancillary network services such as voltage control, avoided network costs, lower losses, provision of steam from renewable based cogeneration and provision of other products or services (such as waste management). Intermittent renewable generation options will be less successful in obtaining such benefits.

In principle, 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. To the extent that renewable generation may confer additional benefits to electricity customers, the level of these benefits will impact on the REC price outcomes.

2.1.4 Basis of method

Projecting renewable energy certificate prices and the technology mix likely under MRET requires the use of a sophisticated model of the Australian electricity system. The approach used in this study 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.

Locational 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. Other benefits of renewable generation also vary by location.

Two models have been developed to project prices of electricity and RECs. The models account for interactions amongst market participants based on the relative marginal costs of generation units and the bidding strategies of generator portfolios.

The wholesale electricity market simulation model depicts each of the generators operating in the electricity market and demand on an hourly basis.

The REC market 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 long run marginal 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.

Because the two models consider the interactions of each generating unit, they can also be used to predict the technology mix. The combination of plant in each year is determined using a linear programming algorithm that selects plant on the basis of least cost to the system[2]. Cost is defined as

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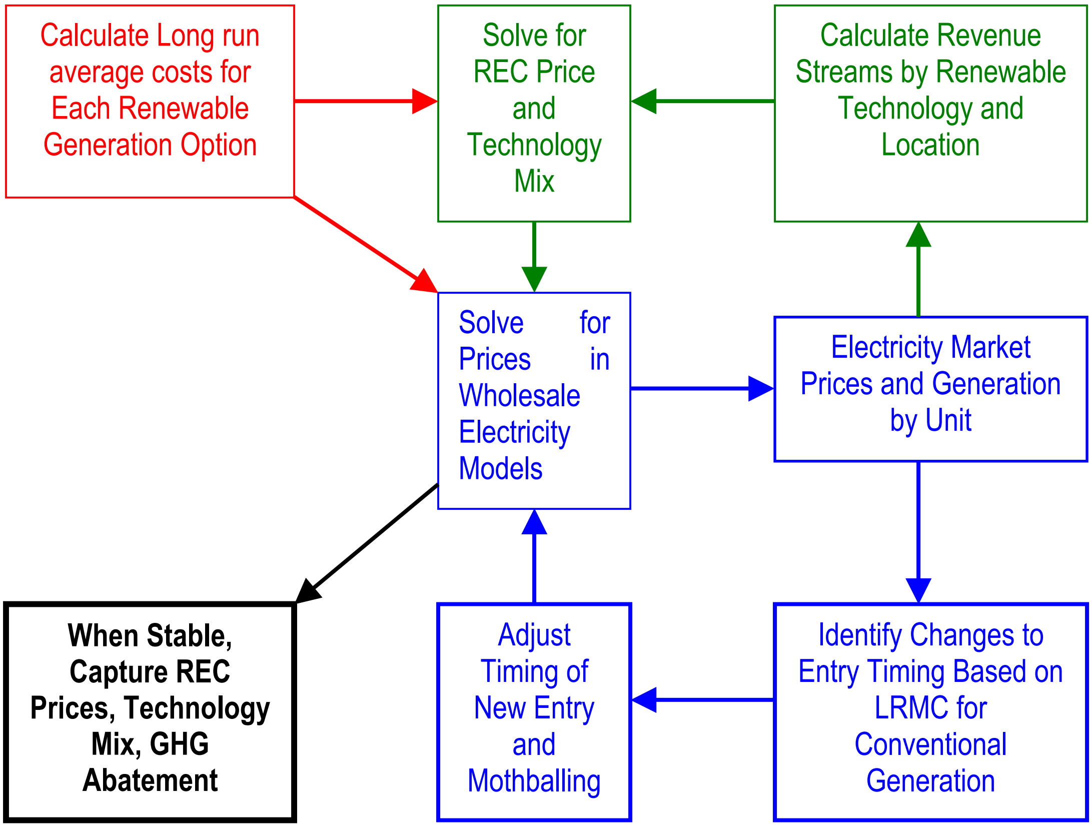
[2] The price is determined simultaneously as the marginal cost of the last plant selected to meet the demand for RECs in any year.

annualised cost of generation minus any revenue from sales to the wholesale market or from other sources[3].

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. Each stage of the modelling approach is repeated until stable wholesale market prices and REC prices are achieved.

Figure 2.2: Overview of method for projecting REC prices and technology mix



Note: LRMC = long run marginal cost of electricity generation. It is a measure of the cost of new plant per unit of electricity produced by the plant. It is calculated as the net present value of all costs of a new plant over its assumed life divided by the net present value of the output over its life, where the discount rate used is equal to the weighted average cost of capital.

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[3] Other revenue can include levies received from local councils for avoiding landfill charges, payments for avoiding network upgrades and revenue from sales of by-products (such as cleaned recyclable materials from some waste to energy projects)

2.2 Electricity Market Model

The Act specifies that the renewable energy target scheme applies to electricity sales in all grids above a specified threshold of 100 MW. Based on this threshold, grids included are:

- The National Electricity Market (NEM), covering the interconnected grids of Queensland, New South Wales, Victoria and South Australia. Although not yet interconnected, the Tasmanian grid is also part of the NEM and included in the renewable energy target scheme.
- The South West Interconnected System of Western Australia (SWIS).
- The North West Interconnected System of Western Australia.
- The Darwin - Katherine Interconnected System (DKIS).
- The Mt Isa Region grid.

Although customers supplied by smaller grids are not liable under the scheme to source electricity from renewable generation options, renewable energy in those systems can still contribute towards meeting the target in other grids.

Only the NEM, SWIS and the DKIS were considered to be important for the RECs market. Some renewable projects will be commissioned in other grids, but these will likely comprise only a minor proportion of the total market.

Modelling of the 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 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).
- Where an auction market exists, a range of bidding options for thermal plant
- 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.

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.

The models are used to project the spot market price in each hour. Electricity prices are determined by the bid of the last plant dispatched. Prices and costs forecast in this manner represent wholesale prices including network losses, but do not include network charges or retail mark-ups.

Information required to forecast generation and electricity prices 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, start-up times and ramping rates.
- Data on fuel costs for each plant including mine mouth prices (or ex-processing plant 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 monthly basis.
- Capital costs for new generating plant.

For each period the model then chooses generation from plants in order from the cheapest to the most expensive until the demand for that period is met. Additional capacity such as refurbishments or expansions are handled in this same manner and added to the available generation to meet demand.

2.3 RE Project Database

MMA has a detailed database of renewable energy projects covering existing, committed and proposed projects that supports our modelling of the REC price path. It contains 344 existing projects, 33 committed projects (500MW), 120 planned projects (2,960 MW) and 79 potential projects (810 MW). This means a potential of over 4,270 MW of new capacity and 18,500 GWh of generation that may enter the market.

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 each project.

There is also over 700 generic plants representing nearly 7,000MW of capacity for projects that have not yet been considered. Information for these projects comes from a wide range of sources and is well documented. The limit to each technology is based on the potential total resource that may be possible for each technology but have yet to be exploited. For example, the Australian Wind Energy Association claims sufficient wind resources to support 10,000 MW of wind generation. Based on the assumption that the most prospective resources are exploited sooner, we develop generic projects based on the resource potential in each State and with a progressively higher cost structure than current or planned projects.

2.4 RECs Market Model

Certificate prices are forecast for the most likely outcome in terms of electricity price, availability of renewable resources and generation costs. In this study, the impact of short-term factors that may affect certificate prices have not been modelled. Such factors include trading strategies to support prices above marginal cost and variations about expected generation levels of intermittent generation.

The forecast of REC prices is based on the assumption that the price of the REC will be the difference between the levelised cost[4] of the marginal renewable generator and the price of electricity achieved for that generation. The basic tenet behind the method is that the REC price provides the revenue, in addition to the electricity price, that is required to make the last required renewable energy generator to meet the REC target viable.

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, resulting in the requirement for iteration of the market price forecast and the REC price forecast.

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[4] Levelised cost is the average per MW cost of generation required to be earnt over the output from a project over its life, where the costs include a commercial rate of return. Mathematically, it is equal to the net present value of total costs (including capital, operating and fuel costs) divided by the net present value of the projected output of the plant over its life. The net present values are calculated using the weighted average cost of capital for a typical project.

- Under MRET, 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.

- Because capital costs are sunk, installed and committed generators are assumed to be operating with just the marginal cost of generation considered in the modelling. These marginal costs are lower than the long run marginal costs for new units, so that committed plant are not likely to set the price in RECs in any year.

- Resource and other constraints limit the uptake of renewable generation. This is reflected in the model in two ways depending on the type of constraint. Physical limits to production are input into the model as a limit on the amount of new generation that can enter the market in any year. Resource constraints, for example fuel availability, are modelled by increasing the marginal cost of the resource.

The optimisation requires that the interim targets are met in each year (by current generation and banked certificates). Banking is determined by calculation of the net present value to the market if a plant is introduced earlier. The model chooses the timing of entry of plant and hence REC prices such that the cumulative target at the end of the study period is met at least cost.

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.

The MMA REC 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 long run average cost of generation using a 9.5% real pre-tax weighted average cost of capital over a 15-year investment horizon. The 15-year investment horizon was used as a typical period over which contracted energy sales would be required to enable financing of a project. The weighted average cost of capital estimate is also based on existing market rates for generation investments. Where data has been published the costs include the costs of connection to the grid, which can form a significant proportion of the capital costs of a project, particularly where no local transmission wires are available.

- The projected spot market price in each of the regions of NEM, SWIS or the DKIS is used to derive the price that a generator could obtain for its power generated. Wholesale electricity prices are determined on an hourly basis for each week of the study period. Average hourly prices are used to determine revenues earnt.
- Regional wholesale electricity prices are assigned to all renewable projects in the database according to location and start date. The electricity prices are weighted 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, photovoltaics 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.
- Revenues from other sources, such as fees for avoided landfill charges, are estimated for each project. Revenue from other sources is restricted. Avoided transmission charges are assumed to be not applicable to intermittent generation options. They only apply to projects known to be located close to load centres. Only variable fees are assumed to be avoided, which provides a maximum benefit of about $5/MWh. Other revenue is only assumed to apply to some waste-to-energy projects, with the benefit assumed to be less than $1/MWh. State Government rebates applying to solar hot water heaters are also assumed to be an additional revenue source.
- Potential revenues from wholesale market transactions and other sources for each project are levelised for the life of the project. The levelised revenue is then subtracted from corresponding renewable project long run marginal cost to derive the net costs required to be met through sales of RECS.
- 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 next 15 years of generation are discounted with the electricity sales income, and revenues from any other programs (e.g. steam sales). The discounted cash flow

compared with the long run average cost indicates the 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, and also subject to resource constraints, REC creation and surrender constraints. The resource constraints are indicated by capacity available from each source and region in each year.
- The resulting MW installed and generation levels are then input into wholesale electricity market model to determine the resultant pool price changes that in turn impact the REC prices.
- The resulting regional pool price paths are iteratively input into the initial step above until stable pool price paths, REC paths and installed renewable generation options are achieved.

Technology mix and investment levels are forecast simultaneously with the forecast of REC prices.

There are three assumptions to the method:

- Plant already operating or committed are assumed to remain in operation for the duration of MRET regardless of prices received for RECs and electricity. This assumption is based on the fact that most of these generators are underwritten by long-term contracts and the fact that their capital costs are sunk.
- Planned projects are assumed to enter the market when demand dictates. Projects are selected on the basis of ascending long run marginal costs, with the amount selected in any one year determined by the demand for certificates in that year. Once selected, the projects are assumed to remain operating for the duration of MRET (even though declining technology costs over time mean that there may be lower cost options in the future).
- In scenarios where operating, committed and planned projects are insufficient to meet demand for certificates, additional generation is selected from generic projects. Based on rational behaviour, it is assumed that the lowest cost resources for each technology will already be exploited or considered. Thus, the costs of generic projects are assumed to be greater than the highest cost planned project.

The next lowest cost generation operation will be installed in a given period if the interim target has not been reached, or if the present value of the certificates able to be earned in the current year and redeemed in future years offsets the incremental cost of generation for that year. This means that excess generation above the interim target can occur. Adding this plant will also increase the REC price for that year.

2.5 Macroeconomic Model

Wider economic impacts were estimated using results from a previous study undertaken for the AGO using a computable general equilibrium model of the Australian economy, called MMRF Green, developed by the Centre of Policy Studies at Monash University. Results of the wider economic impact are estimated from the relationship between GDP or employment and increases in the delivered price of electricity to customers derived from the results of the previous study.

2.6 Assumptions

Key assumptions for this analysis include the drivers affecting electricity price and assumptions on the cost of renewable generation. Details of the assumptions behind the simulations of the electricity market are provided in a report completed by MMA for the AGO and also available to the MRET Review Panel[5]. Assumptions behind the calculation of the costs for renewable energy generation are also contained in the report provided to AGO.

2.6.1 Macro-economic assumptions

All monetary values are on a real mid 2003 Australian dollars basis.

We assume a real pre-tax discount rate of 9.5%pa. The current Treasury 10 year bond rate, an indicator of a low risk discount rate, is about 5% in nominal terms and about 2.5% in real terms. We assume a risk premium of 7% to reflect the uncertainty over the impact of a competitive electricity market, the additional uncertainties facing renewable generators and to reflect the rate of returns to independent power producers.

2.6.2 Structural assumptions

Major energy market assumptions used in the modelling include:

- Current institutional arrangements remain largely intact. The current structure of Government Owned Enterprises in electricity generation also does not change. Except in Western Australia only minor reforms to

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[5] MMA (2003), *Economic Impacts of Changes to the Mandatory Renewable Energy Target*, report to the Australian Greenhouse Office.

market structures occur. The recommendations made by the Western Australia Electricity Reform Task Force in their draft report are adopted.

- Demand growth projections for medium growth rate case as used in the AGO study. The demand forecasts were allocated across the three grids based on proportional allocation of demand provided in other published projections (ABARE, NEMMCO, Western Power, Northern Utilities Commission). Peak demands were calculated using the load factor implied in other published demand forecast for the major grids.
- Options to meet growth in demand for electricity selected on the basis of minimum costs. That is, the least cost option is chosen to meet the demand growth, selected from new generation, transmission and demand management options. Current technological options for generation are used.
- Renewable generation options are assumed to bid in at a level to ensure dispatch and therefore never set the price in the wholesale electricity market. 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.
- Real fuel prices decline. Both coal and gas prices escalate at about 75% of CPI. This is based on current market trends and assumes moderate competition in gas markets will emerge either through increased integration of the gas network or new suppliers coming on stream.

2.6.3 *Final and interim targets*

The interim targets for the current MRET scheme are specified in the Act and include a final target of 9,500 GWh of renewable generation in 2010. The interim targets for the proposed new targets are presented in Table 2.1.

Each generator, established after 2005, can only be eligible for 15 years worth of RECs.

Table 2.1 Interim Targets (GWh/year)

Year	Target
2001	300
2002	1,100
2003	1,800
2004	2,600
2005	3,400
2006	4,500
2007	5,600
2008	6,800
2009	8,100
2010	9,500
2011	10,550
2012	11,600
2013	12,650
2014	13,700
2015	14,750
2016	15,800
2017	16,850
2018	17,900
2019	18,950
2020 Onwards	20,000

2.6.4 *Shortfall charge*

Two differing shortfall charges have been applied to the above scenarios. Under the first, liable parties who fail to submit the required number of certificates in each accounting period will be required to pay a penalty for the shortfall of $40/MWh. This penalty is not indexed to CPI. The penalty is also not tax deductible so that under current company tax rates a liable party would be indifferent between paying the penalty or purchasing certificates up to a price of around $57/MWh in mid-2003 dollars. The second shortfall charge is the same as the first except the value in 2010 is indexed to CPI from 2010 onwards. Thus from 2010 onwards the shortfall charge remains at an after tax value of $48 based on an annual CPI rate of 2.5%.

2.6.5 *Capital costs*

The capital cost reductions over time are applied to current capital costs as a percent reduction in cost for each year of project delay. The largest reductions are applied to the newest technologies, particularly for wind and solar generation, which are expected to show rapid reductions in capital cost over the next 15 years.

Capital costs are assumed to reduce by:

- For solar thermal and PV technology, 8% per annum until 2015, thereafter 5% per annum until 2025, thereafter 2% per annum.
- For wind generation, 5% per annum until 2015, thereafter 2% per annum.
- All other technologies, 2% per annum

Increases in costs will occur for some resources, as more marginal resources are required. This will be the case for constrained resources such as for hydro, landfill gas, and sewage gas and in the longer term also for wind.

A summary of project costs is contained in Table 2.2.

Table 2.2: Long run average costs of renewable generation options in 2010, $/MWh (mid 2003 dollar terms)

Renewable Generation Type	Minimum	Maximum
Refurbished Hydro	49	120
Wind	62	120
Bagasse	51	108
Rural Biomass	47	120
Landfill gas	41	110
SHW	43	90
MSW combustion/gasification	75	120

Note: Long run average costs represent average cost (including capital, transmission, operating and fuel costs) calculated using 9.5 % pre tax cost of capital.

Generic projects are developed on the basis that further projects will be proposed by project developers to make use of additional available viable resources. The extent to which this is likely to occur is assessed separately for each technology or resource. Resources such as landfill gas and sewage gas are limited and the further available viable resource is tightly constrained. There are also absolute resource constraints for rural wastes such as bagasse, sawmill waste and agricultural residues. Hydro-electric generation is constrained by the extent to which sites are available for new generators at existing structures and the extent to which pre-97 hydro stations are able to increase output. Constraints on development of wind resources are more complex and subtle and centre on the interaction between siting, wind speed, project economics and land-use planning.

Long run marginal generation costs are calculated for each project using available or estimated values for capital costs, O&M costs, and fuel costs.

2.6.6 Treatment of existing renewables

Existing renewables are defined as those generators commissioned before 1997 at the time the measure was introduced. These renewables are not eligible for renewable energy certificates, except for the proportion of output above their calculated baselines.

Increases in hydro-electric generation that may be obtained from upgrading the turbines or other equipment on existing hydro-electric systems are included. These projects are assumed to be scheduled throughout the target period to achieve a realistically achievable sequence of plant expansion. Tasmania's hydro-electric potential has also been modified to account for the higher energy that is possible as a result of Basslink. With Basslink, generation from the mainland can be imported in off-peak periods resulting in less hydro-electric generation in those periods and a build up of water levels in storages. Because of the higher storage levels, the potential energy of the water is increased resulting in the potential to generate more energy during peak periods. Based on studies undertaken for the Basslink project, we assume that the additional hydro-electric generation with Basslink is about 270 GWh above the 1997 baseline.

3 RESULTS

Key results of the analysis are described in this section. The discussion focuses on the impacts of a 20,000 GWh target on REC prices, renewable generation and compliance costs. Indicative impacts on the national income and employment are also discussed.

Results are presented for two scenarios, both involving the an ultimate target of 20,000 GWh from 2020 onwards. The two scenarios are:

- *Unindexed scenario*, where the current shortfall charge is not indexed.
- *Indexed scenario,* where the shortfall charge is indexed with CPI at its 2010 value from 2010 onwards.

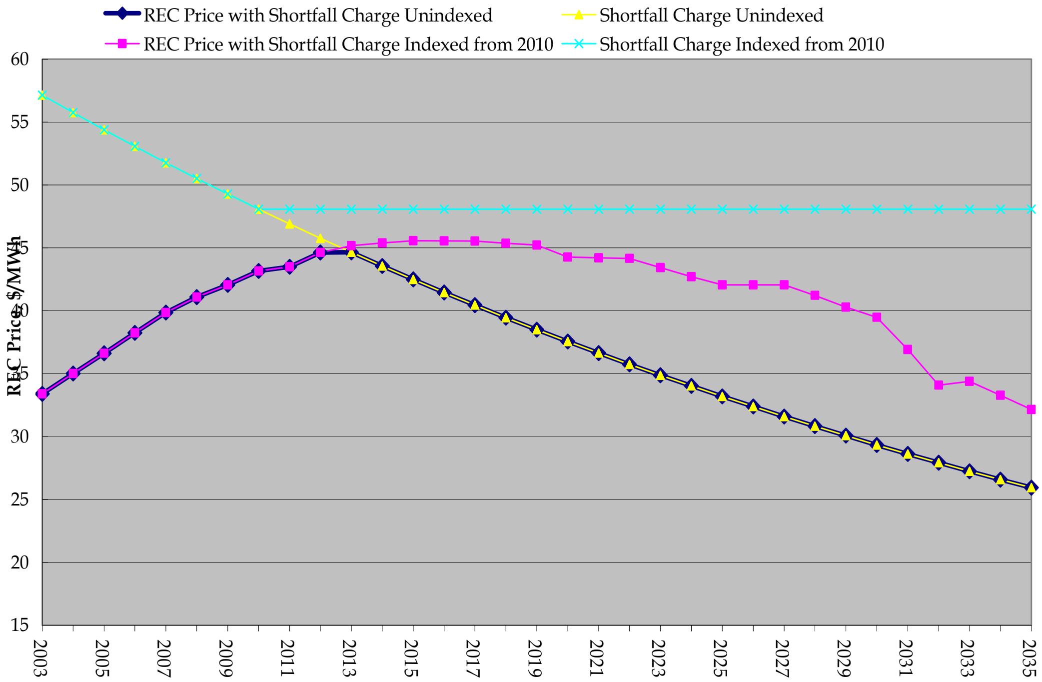
3.1 REC Prices

Forecasts of the REC price for both the unindexed and indexed scenarios are shown in Figure 3.1. For the unindexed scenario, the price of certificates reaches the price cap implied by the shortfall charge in 2013. Thereafter, prices follow the unindexed shortfall charge implying that the net cost of additional renewable generation is higher than the shortfall charge. Once the price is constrained by the shortfall charge, the price then becomes the shortfall charge. The reason for this is the assumption that retailers would rather pay the penalty of the shortfall charge than pay more than the shortfall charge for RECs.

Prices peak in the unindexed shortfall charge case at $44.60 in 2012 and falls to $25.90 in 2035. The decrease is due to the shortfall charge falling.

For the indexed shortfall scenarios, two key results emerge. First, the price never reaches the cap implied by the indexed shortfall charge. Indexing of the shortfall charge from 2010 is therefore likely to be sufficient to allow the achievement of the 20,000 GWh target. Second, prices for certificates increase initially and then decrease over the longer term. Prices are forecast to peak at about $45.60/MWh in 2015 and fall to about $32.20/MWh in 2035. Prices increase initially as the demand for RECs increases above the annual targets. It is less costly for liable parties to purchase more RECs early to be redeemed at a later date. Prices also increase in the period to 2015 as lower yield wind generation and biomass projects with higher fuel costs are required to meet the targets. Prices eventually peak and fall as technology costs continue to decline and outweigh the increase in cost from sourcing more marginal wind generation[6].

Figure 3.1: Forecast REC Prices



Prices are forecast to be higher in the period to 2020 compared to the case where the target remains at 9,500 GWh. In previous analysis undertaken for the AGO, the REC price for the existing target was forecast to reach about $36/MWh in 2008 and remain at that level thereafter. With a higher target, prices increase even in the period prior to 2010 as liable parties find it more economic to bring on more renewable generation early to meet certificate requirement in a later period. A higher target also requires more expensive renewable generation resources.

3.2 Generation

The amount of new renewable energy resulting from the MRET scheme with the new target can be seen in Figure 3.2.

The amount of generation for both unindexed and indexed scenarios is similar until the unindexed shortfall charge is reached. Not indexing the shortfall charge constrains the amount of new generation with the total amount of generation for this scenario reaching around 13,500 GWh in 2014

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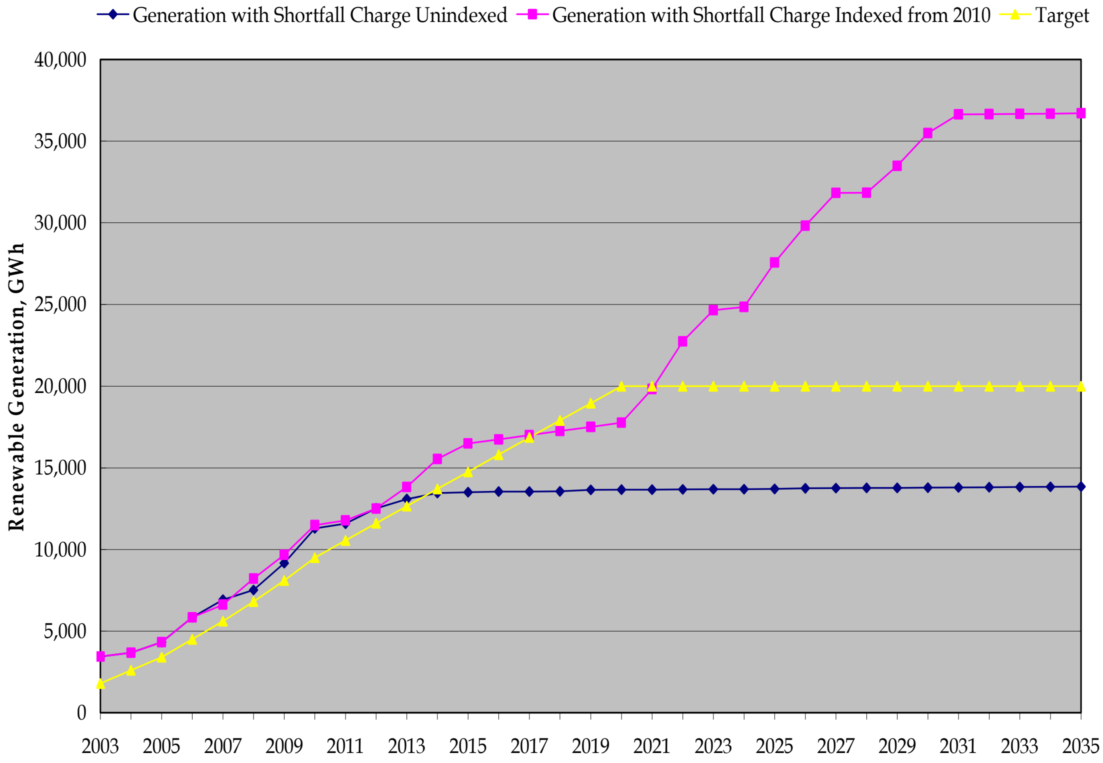
[6] There are large resources of wind generation for which the marginal cost increase only marginally as more of this generation is required to brought on-stream. In the model results, the modest increase in marginal cost as wind resources with marginally less yield is required is offset by the assumed decrease in capital costs of wind generation over time.

when the REC price is equal to the shortfall charge. After 2014, the level of generation increases slightly to reach 13,900 GWh by 2035. Once the REC price for this scenario reaches the shortfall charge, only minimal new generation is able to enter the market as the cost of new generation falls at a lower rate than that of the shortfall charge. Retailers would be financially better off to pay the shortfall charge under this scenario than pay more for new generation to enter the market.

Figure 3.2: Total Renewable Generation for 20,000 GWh Target



Despite the fact that generation levels off after 2014 in the unindexed scenario, the cumulative level of renewable generation exceeds the cumulative target until about 2017. Banking of certificates in the period to 2010 allows the target to be met for a longer period.

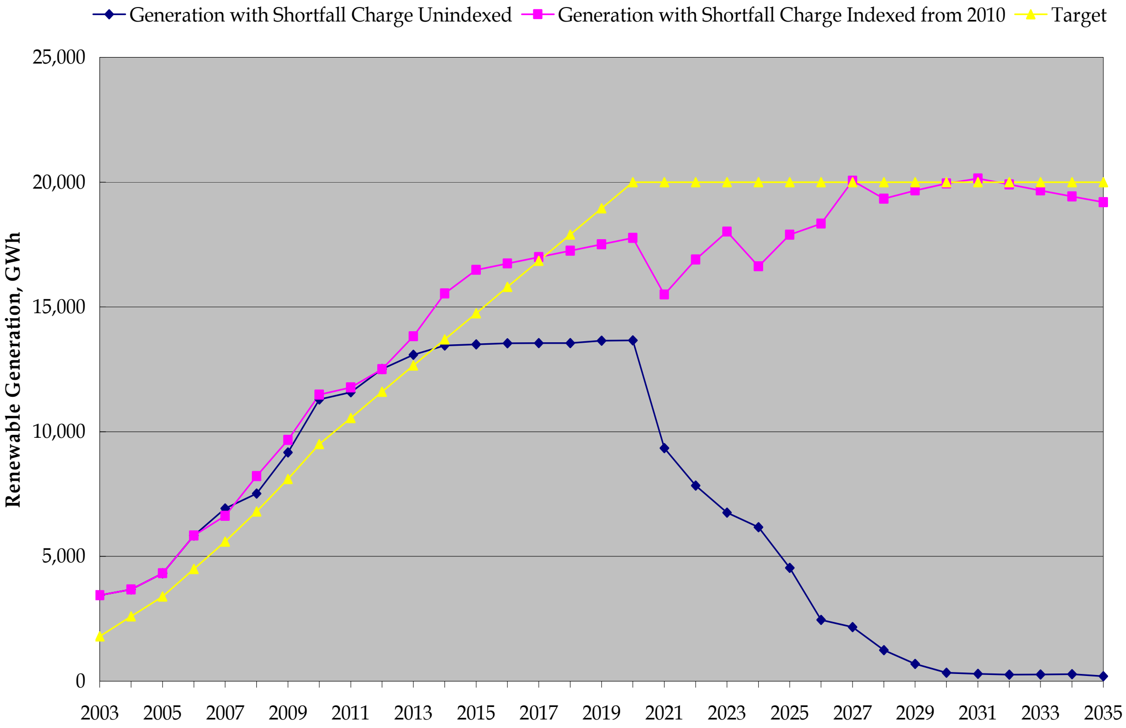
With the shortfall charge indexed from 2010, the amount of renewable energy is not constrained. Prior to 2020, the total amount of renewable generation reaches about 18,000 GWh compared with around 8,500 GWh under the current MRET. More renewable generation than the target early in the period is used to meet liabilities later on in the period to 2020.

After 2020, total renewable generation exceeds the target of 20,000 GWh in the indexed scenario, flattening out at about 36,700 GWh from 2031.

The higher level of generation occurs for two reasons. First, renewable generators no longer eligible for RECs after 15 years of operation are expected to continue to generate after the 15 year expiry date[7]. Many renewable generators are expected to operate for 20 years or more. These generators can continue to earn revenue from wholesale electricity markets after their eligibility to earn RECs expires. Declining technology costs as well as improvements in efficiency of generation means that these plants could effectively be replaced from 2020 at a cost which does not require a subsidy. There is still an incentive to increase the level of output as any additional output above what they were originally generating is eligible to earn RECs. Second, more new renewable generation is required to meet the shortfall in liabilities as eligibility for older renewable plant expires.

The amount of generation eligible to create RECs can be seen in Figure 3.3. In the unindexed scenario, the level of eligible generation falls as the costs of additional renewable generation exceeds the shortfall charge. As a result, very little new generation comes into the market after the REC price reaches the shortfall charge in 2013.

Figure 3.3: Renewable Generation Eligible for RECs for 20,000 GWh Target



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[7] It is assumed that renewable generators existing prior to 2005 can only create RECs until 2020. All generators commissioned after 2005 can only create certificates for 15 years. Thereafter, the generators can only earn RECs if they generate above their baselines, which will be set at their original generation levels.

For the indexed scenario, the level of eligible generation continues to grow until it reaches 20,000 GWh. With the shortfall charge indexed from 2010, new renewable generation continues to enter the market in the latter half of the period as the cost of this generation is always below indexed shortfall charge.

The cumulative total of certificate generation over the period to 2035 in the indexed scenario is either above or at the cumulative target under this scenario. Banking of certificates prior to 2020 compensates for the drop in RECs created in the period from 2017 to 2027.

3.3 Technology Mix

Wind is by far the most dominant renewable energy resource accounting for approximately 40% of the total generation in 2010 for both scenarios. This figure remains constant for the unindexed shortfall charge scenario and rises to 64.5% in 2030 for the indexed shortfall charge scenario with the majority of new generation entering the market after 2020 being from this source.

Generation from bagasse makes up the next highest proportion of approximately 15% in 2030 for both targets. Bagasse generation is heavily constrained by the amount of fuel available.

For the unindexed shortfall charge case, the proportion of each type of generation remains approximately constant over the period as the total level of generation remains constrained.

Table 3.1: Proportion of Total Generation by Each Fuel Source, %

	Unindexed Shortfall Charge			Indexed Shortfall Charge		
	2010	2020	2030	2010	2020	2030
Waste (MSW, WTE)	4.2	4.7	4.6	4.1	4.0	2.0
Biomass	0.1	0.1	0.1	0.1	0.1	0.0
Bagasse	8.9	14.8	15.0	8.8	24.2	15.1
Sewage	2.4	2.0	2.0	2.4	1.6	0.8
Landfill Gas	3.0	2.4	2.4	2.9	1.9	0.9
Agricultural Waste	1.6	1.3	1.3	1.6	1.0	0.5
Black Liquor	0.7	0.5	0.5	0.6	0.4	0.2
Food	0.3	0.3	0.3	0.3	0.2	0.1
Wood Residues	15.6	12.9	12.8	15.4	9.9	5.0
Geothermal	0.6	0.5	0.5	0.6	0.4	0.2
Hydro	13.0	12.8	12.7	14.5	10.0	7.6
Wind	41.4	40.4	40.1	40.7	40.8	64.5
Solar	8.2	7.1	7.5	8.0	5.4	3.0

The indexed shortfall charge case however is a different story. The amount of renewable generation is unconstrained by the shortfall charge case and therefore the proportion of each technology changes significantly over time. The proportion of generation from sources other than wind drops significantly due to the large volume of wind generation entering the market after 2020 to ensure the specified target of generation is met.

Most sources increase in absolute terms.

Compared with the current MRET target, both wind generation and bagasse based generation is projected to increase significantly.

3.4 Compliance Costs

The cost of compliance can be seen in Table 3.2. The cost per unit of electricity sold to customers, averaged over the entire period, for the unindexed shortfall charge scenario is $1.74/MWh. This compares with $2.03/MW as the shortfall charge is indexed.

The total cost over the entire period to consumers for the unindexed shortfall charge is $6,027m compared to $7,053m when the shortfall charge is indexed. For the unindexed shortfall charge scenario, the cost is much less by generation than by target as the target level of generation is never reached. For the indexed scenario, the cost by generation is also less than the cost by target due to the effect of banking. There is more generation than the target in earlier years due to the money saved from banking and later surrender of lower cost certificates.

Table 3.2: Compliance Costs to Customers, mid 2003 dollar terms

		Unindexed Shortfall Charge	Indexed Shortfall Charge
Cost per unit of energy			
- Total study period	($/MWh)	1.74	2.03
- 2010	($/MWh)	1.90	1.90
- 2020	($/MWh)	2.61	3.22
- 2030	($/MWh)	1.67	2.36
NPV cost to customers	($m)	6,027	7,053

Note: Compliance costs for total study period is equal to the net present value of the total cost of meeting certificate liabilities over life of the MRET scheme. Compliance cost in actual years is discounted to mid 2003 dollar terms. Compliance cost in 2020 for the indexed charge is the highest annual compliance cost for this scenario.

Compliance costs are slightly higher than for the current MRET target. Compliance costs are forecast to be $1.14/MWh over the period from 2003 to

2020 for the current MRET target compared with $1.66/MWh for the unindexed scenario and $1.81/MWh for the indexed scenario over the same period[8]. The higher compliance cost reflects the higher target and the higher certificate price.

Assuming the price of RECs always equals the shortfall charge will increase compliance costs. Making this assumption, compliance costs over the study period become:

- $1.92/MWh for the unindexed scenario (instead of $1.74/MWh when calculating the compliance costs with the REC price).
- $2.44/MWh for the indexed scenario (instead of $2.03/MWh when calculating the compliance costs with the REC price).

3.5 Wholesale Prices

A comparison of wholesale prices is shown in Table 3.3. The prices include the cost of electricity and the cost of purchasing RECs.

Prices are similar between cases in 2010 as the level of generation for both scenarios remains unconstrained by the shortfall charge.

Table 3.3: Wholesale Electricity Prices, $/MWh

	Unindexed Shortfall Charge			Indexed Shortfall Charge		
	2010	2020	2030	2010	2020	2030
Tasmania	35.2	36.6	36.3	35.2	37.1	36.9
South Australia	49.8	51.2	50.4	49.8	51.8	51.1
Victoria	44.2	51.4	50.4	44.2	52.0	51.1
New South Wales	41.9	37.6	37.9	41.9	38.2	38.6
Queensland	37.3	40.1	38.7	37.3	40.7	39.4
Western Australia	50.8	46.6	46.5	50.8	47.0	47.0
Northern Territory	58.5	53.8	53.6	58.5	54.4	54.2
Australian average	42.3	42.7	42.2	42.3	43.4	42.8

Prices remain lower in 2020 and 2030 for the unindexed shortfall charge scenario as this shortfall charge effectively caps the REC price lower than the indexed shortfall charge scenario. The Australian average rises by

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[8] The estimates of compliance costs reported in this paragraph equal the costs to customers per unit of electricity sales for the period from 2003 to 2020. Thus, the compliance cost estimates for the indexed and unindexed scenarios are lower than those reported in Table 3.2 for the total study period as the estimates in the Table are for the period from 2003 to 2035. The shorter period was used in this case to enable proper comparison with the cost under the current MRET scheme, which expires at the end of 2020.

$0.70/MWh in 2020 and 2030 as a result of indexing the shortfall charge. The Australian average for the current MRET case for 2020 is $41.80/MWh. For the unindexed shortfall charge case, prices increase above the current MRET case by 2.2% and for the indexed shortfall charge case, prices increase by 3.8%

3.6 Emissions

Compared with the current MRET target of 9,500 GWh, the abatement over the period is shown in Table 3.4. The indexing of the shortfall charge results in an extra 12.3 Mt of CO_2e per annum abated in 2030 compared with the unindexed scenario. This is due to the extra amount of renewable generation allowed by the unconstrained indexed shortfall scenario.

Table 3.4: Additional Abatement, Mt of CO_2e

	2010	2020	2030
Shortfall Charge Unindexed with MRET	1.1	4.7	3.6
Shortfall Charge indexed from 2010 with MRET	1.5	7.2	15.9
Shortfall Charge Unindexed without MRET	9.0	13.4	11.6
Shortfall Charge indexed from 2010 without MRET	9.4	15.9	23.9

Note: * The level of abatement in 2030 depends on the assumptions about what will happen to the abatement produced by the current MRET from 2020 to 2030. Based on the analysis in this report it is reasonable to assume that the renewable generation encouraged by current MRET will continue beyond 2020. Thus, estimates from 2030 assumes that the level of renewable generation under current MRET continues beyond 2020 and the level of annual abatement beyond 2020 for the current MRET target is equal to average level of abatement in the period from 2016 to 2020. The abatement in 2030 for the unindexed and indexed scenarios includes abatement from renewable generation no longer eligible to earn certificates.

The cumulative level of abatement above that achieved with the current MRET scheme from 2003 to 2035 is about 248 Mt for the indexed scenario and 96 Mt for the unindexed scenario.

The indexed shortfall charge scenario abates more emissions as the level of renewable generation is significantly higher, thus more fossil fuel generation is displaced. The cost of this extra abatement to the electricity sector in 2030 is $48.2/tonne CO_2e for the unindexed scenario compared to $32.9/tonne CO_2e for the indexed scenario (see Table 3.5). This abatement cost is calculated on the forecast amount of renewable generation for the indexed case and on the target amount of certificates required to be redeemed in the unindexed case. The different basis for calculation reflects the actual costs incurred in each scenario, with a higher level of generation than the target occurring in the indexed scenario and a lower level of generation than the target occurring in the unindexed scenario. For the unindexed scenario, end-use customer still pay the shortfall charge even though no renewable generation is undertaken and thus cost should be added to the cost of abatement. Calculation of the cost of abatement is also based on the total amount of renewable generation, not just the amount of renewable generation eligible for certificates.

The cost of abatement to the economy in 2030 is $32.9/tonne CO_2e for the indexed scenario and $22.9/tonne CO_2e for the unindexed scenario. This cost is lower than the cost to the electricity sector because it does not include the transfers of income from consumers to renewable generators.

Table 3.5: Cost of Abatement, $/tonne CO_2e, mid 2003 dollar terms

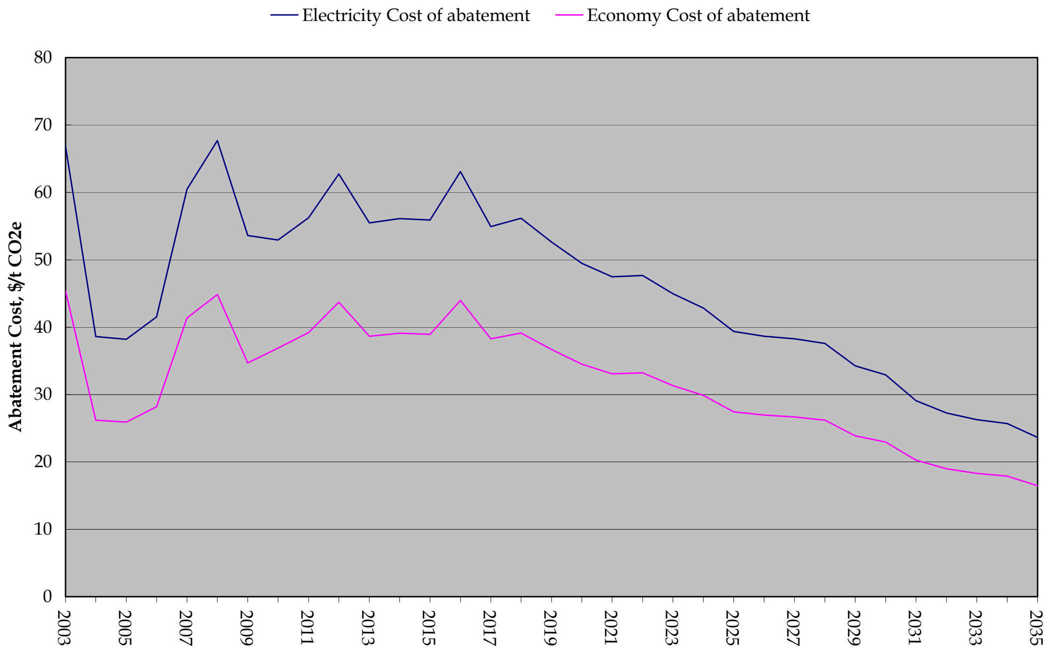
	2010	2020	2030
Shortfall Charge Unindexed	54.4	53.4	48.2
Shortfall Charge Indexed from 2010	52.9	49.5	32.9
Economy Wide Unindexed	35.7	35.0	31.6
Economy Wide Indexed from 2010	35.3	33.0	22.0

Note: Costs are calculated using the level of abatement relative to the no MRET scenario. The cost of abatement is calculated on the amount of total renewable generation and the higher electricity cost of this additional amount of renewable generation. The cost of paying a shortfall charge on certificates not redeemed is also included in calculating the abatement cost in the unindexed scenario.

The cost of abatement rises over the medium term but is expected to fall over long term (see Figure 3.4). For the indexed scenario, the decline in abatement costs does not occur until after 2020. For the unindexed scenario, the decline in abatement costs also does not occur until after 2020, but the decline is at a slower rate (see Figure 3.5).

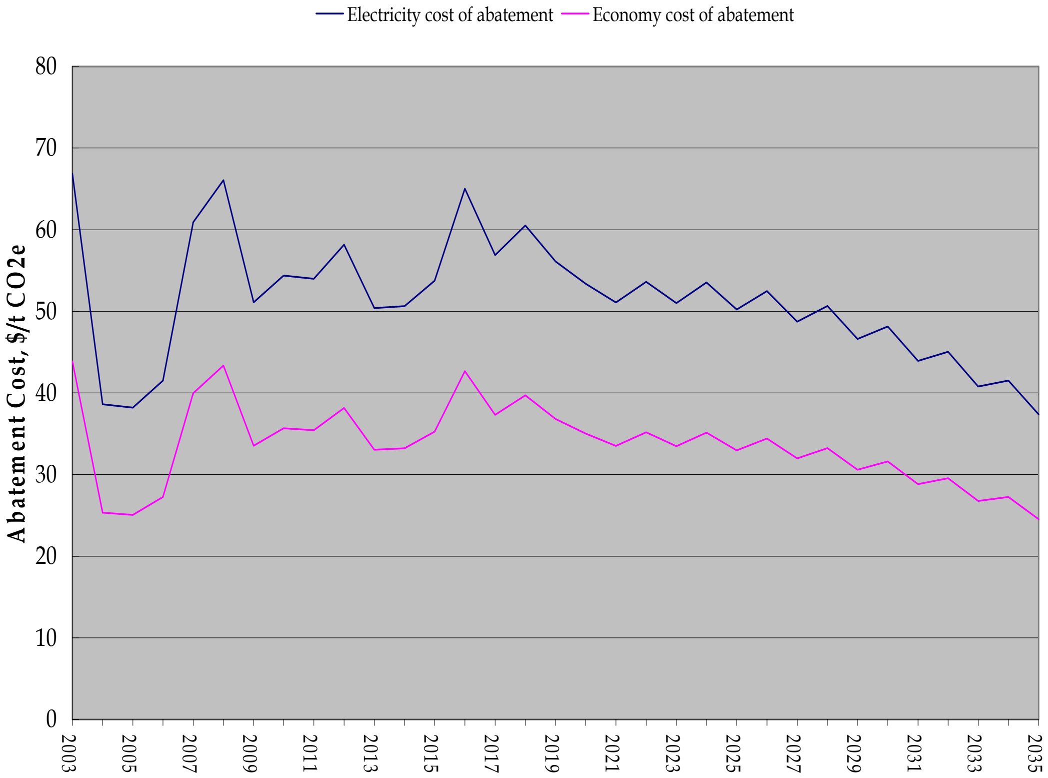
This reflects two factors. First, although the cost of renewable generation rises in the medium term, it eventually falls over the longer term as technology costs decline. Second, part of the additional renewable generation from 2020 is no longer eligible to earn certificates. However, this generation continues because it is now competitive with fossil fuel generation.

Figure 3.4: Forecasts of abatement costs for indexed scenario, \$/tonne CO_2e



Note: Cost of abatement calculated using emissions abated compared to the case if there were no MRET scheme

Figure 3.5: Forecasts of abatement costs for Unindexed scenario, \$/tonne CO_2e



Note: Cost of abatement calculated using emissions abated compared to the case if there were no MRET scheme

3.7 Investment

The amount of investment in the renewable energy sector for the unindexed and indexed scenarios is shown in Table 3.6. The total investment from 2003 to 2030 for the unindexed shortfall charge scenario has an NPV of $6,026m while total investment for the indexed shortfall charge scenario has an NPV of $14,462m. Thus, indexing of the shortfall charge allows for an extra $8,436m to be invested in renewable technologies over the period to 2030.

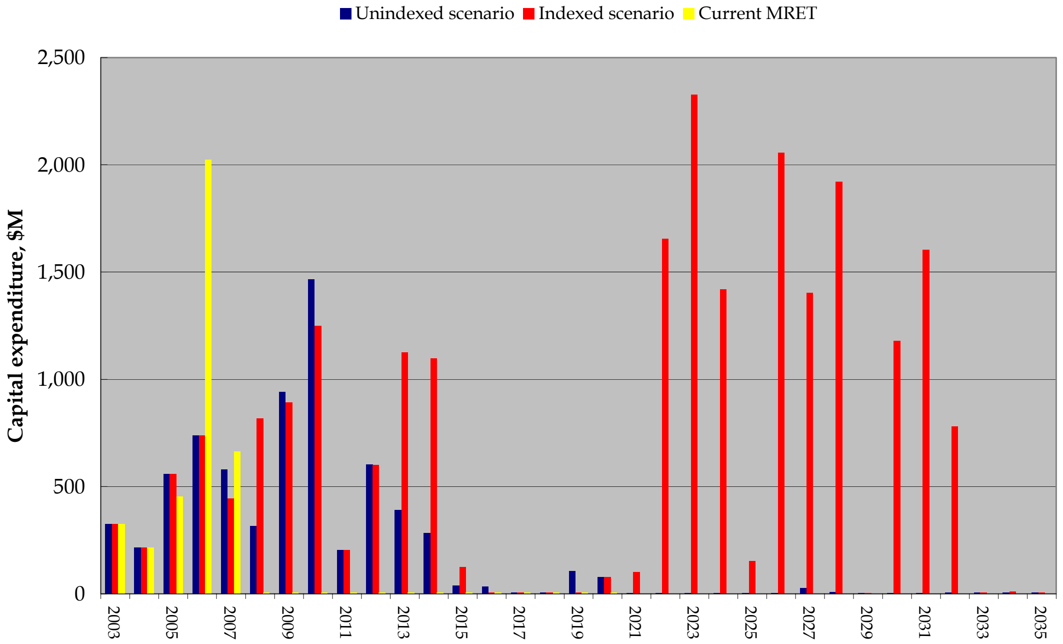
Table 3.6: Net Present Value of Cumulative Investment in Renewable Energy, $M, mid 2003 dollar terms

	2010	2020	2030
Shortfall Charge Unindexed	4,620	5,990	6,026
Shortfall Charge indexed from 2010	4,715	7,269	14,462

Note: Estimates of investment represent the net present value of the cumulative annual investment from 2003 to the year shown.

With the shortfall charge being indexed, higher cost renewable generation sources can enter the market. This allows for a significant increase in investment in the latter part of the study period. The difference can be seen by the forecast annual investment as shown in Figure 3.6.

Figure 3.6: Annual investment in renewable generation, $M, mid 2003 dollar terms



Generation grows to 13,500 GWh in 2014 in the unindexed scenario. Despite the price being at the shortfall charge, there is still some additional investment beyond 2014 in low cost renewables as costs fall and resources become available. However, the level of investment is significantly less than occurs in the indexed scenario beyond 2014.

Investment is likely to be higher and extend for a longer period in both indexed and unindexed scenarios compared with the forecast investment with the current MRET scenario. Under the current MRET target, investment in renewable generation is likely to vanish after about 2007. With an ongoing increase in the target, investment continues to grown in the unindexed and indexed scenarios with a higher target. The pattern of investment for the higher target, particularly if indexation is allowed, is likely to be more favourable to the development of a sustainable renewable energy industry.

There is a large gap in investment under the indexed scenario between 2015 and 2021. Generation increases only modestly over this period as it is above the target level of generation for most years during this period and sufficient certificates have been banked to cover liabilities over this period and beyond. However, in reality the pattern of growth of generation is not likely to match exactly the modelling results due to other constraints not considered. Therefore, there is likely to a smoother pattern to investment than indicated by the model results.

3.8 GDP

The change in GDP compared with the current MRET target can be seen in Table 3.7. In relation to total GDP, the impact is less than 0.08% of GDP over the time period of the analysis for the indexed case and less than 0.07% per annum for the unindexed case.

Table 3.7: Net Present Value of the Cumulative Change in GDP from Current MRET Target, $M

	2010	2020	2030
Shortfall Charge Unindexed	-800	-4,600	-7,700
Shortfall Charge indexed from 2010	-850	-5,100	-8,800

The total change in GDP from the current MRET target over the entire study period[9] for the unindexed shortfall charge scenario has an NPV of -$8,900M while the total change in GDP from the current MRET Target for the unindexed shortfall charge scenario has an NPV of -$10,300M. So with the shortfall charge unindexed, this lessens the effect of the MRET target on Australia's GDP by $1,400 m.

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[9] From 2003 to 2035

3.9 Employment

The number of jobs created in the renewable energy sector in addition to the current MRET target, under each shortfall charge scenario is shown in Table 3.8. With the shortfall charge unindexed there are about 2,100 jobs created in the renewable energy industry. Indexing the shortfall charge in 2010 leads to a total of about 7,000 jobs per annum being created.

Table 3.8: Jobs Created in the Renewable Energy Industry

	Equivalent Full Time Jobs per annum
Shortfall Charge Unindexed	2,100
Shortfall Charge indexed from 2010	7,000

Note: Jobs created are in addition to the jobs created under the current MRET Scheme.

However, with a decline in GDP expected, the economy-wide level of employment is likely to fall. Previous analysis undertaken for the AGO indicates that the overall fall in employment is likely to be minimal.

3.10 Sensitivity Analysis Results

Many assumptions adopted in this analysis were conservative. The use of conservative assumptions would impact on the results obtained particularly on the level of eligible renewable generation in the unindexed case. To test the sensitivity of the results, five additional sensitivities were run on the above results.

The assumptions for these are listed as follows:

1. Coal and gas prices will increase by 20%. This sensitivity was undertaken to reflect two factors. First, coal prices could increase in the long term as higher cost resources are required to be used to meet the market needs. This could outweigh technological improvements in mining. Second, gas resources could diminish over the next thirty years, particularly in the eastern seaboard, requiring more remote and more expensive sources of gas to service the market. The higher coal and gas prices were phased in over a period from 2005 to 2015. However, because fuel prices impact on the long run marginal cost of new fossil fuel generation, which acts as an indicator of prices on the wholesale market, the impact will be felt earlier as prices in the wholesale market goes up to reflect the higher cost of new generation.
2. The capital cost of new coal generation will increase by 20%. This change was applied to the period from 2010 until 2035. This sensitivity was

undertaken to test the robustness of the results to the potential situation of restrictions on the type of new coal-fired technologies that enter the market as a result of other abatement policies. Additional policies for abatement of greenhouse gases will increase the cost of thermal generation and require more expensive and more efficient plant to enter the market. This will increase the price of electricity received by renewable generators.

3. The MRET Review Panel is considering changes to some of the rules governing eligibility of renewable generation. Two changes include widening eligibility of solar hot water heaters and reducing some impediments to fuel from plantation resources eligible. A sensitivity was therefore undertaking to a higher potential of both sources of renewable generation. It was assumed that SHW will increase uptake by 40% and the cost of fuel from plantations will decrease by 20% as a result of changes to the rules under MRET.
4. The premium on returns on debt and equity on renewable generation relative to conventional generation was assumed to remain during the forecast period. However, it is possible the premium could fall as lenders and investors gain confidence in the market. Further, trends in the capital cost of renewable generation are uncertain. They could fall more than was assumed above.

   Thus, a sensitivity was undertaken with the weighted average cost of capital on renewable generation falling from 9.5% to 8.5% from 2005 to 2015. Also the cost of capital was assumed to fall at a faster rate. The cost of capital for PV was assumed to decline by 10% per annum until 2025 then 5% thereafter. Wind generation costs were assumed to fall by 7% per annum until 2015 then 4% per annum thereafter. Capital costs for all other technology sources were assumed to decrease by 4% per annum for the entire period.
5. All the above adjustments to the assumptions included in the one scenario.

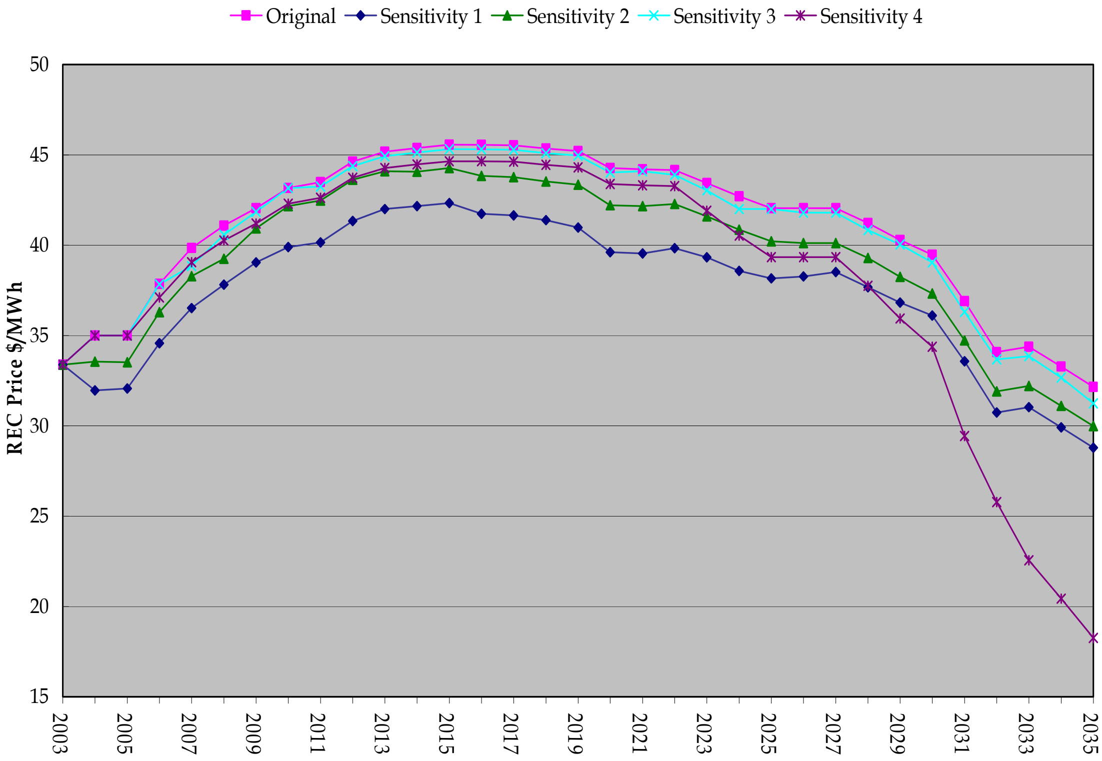
A comparison of prices between the scenarios is shown in Figure 3.7. The effect of increasing coal and gas prices by 20% has the biggest effect on prices, reducing the REC price by about $5 every year. This is due mainly to the renewable energy generators receiving a greater price from the pool and requiring a lower REC price to enter the market.

A change to the capital cost of coal has a similar effect over the period, although with a smaller magnitude. The reduction is approximates $2 every year.

The effect of sensitivity 3 is minimal for two reasons. The first is that the cost of plantation based generation is out of the range of REC price required to enter the market. The second is that due to an increase in only 200 GWh in the uptake of SHW.

The fourth scenario has the interesting effect of causing the REC price to decline rapidly in the latter part of the period. This is due to the decline in capital cost of projects.

Figure 3.7: REC Price Comparison between Sensitivities, $/MWh



For the four sensitivities, the amount of generation under the unindexed shortfall charge case increases even though it is constrained by the shortfall charge. Originally this was not the case as the cost of capital (PV excluded) was decreasing by 2% but the shortfall charge falls by 2.5%. Under the new scenario, the cost of capital falls by 4%, a greater rate than the 2.5% thus making more generation available to enter the market.

Sensitivity 5 produces the closest result to the scenario with the shortfall charge unindexed. Under this scenario, REC prices are likely to be constrained by the shortfall charge between the period of 2021 and 2030 (see

Figure 3.8). To achieve the target, the REC price would need to be at most only about $3/MWh above the shortfall charge. The REC price falls to as low as $15 in 2035 as the cost of new renewable energy approaches that of conventional energy.

With the REC price being constrained for the period between 2021 and 2030, the amount of RECs created is also constrained. Figure 3.9 shows this reduction. With the shortfall charge indexed from 2010, the cumulative target over the period is able to be met. Once this indexation is removed, the total number of RECs created fall short of the cumulative target by 46,000 RECs. Once the REC price falls below the shortfall charge, the total eligible generation rises to meet that target by 2032.

Figure 3.8: REC Price for Sensitivity 5 ($/MWh)

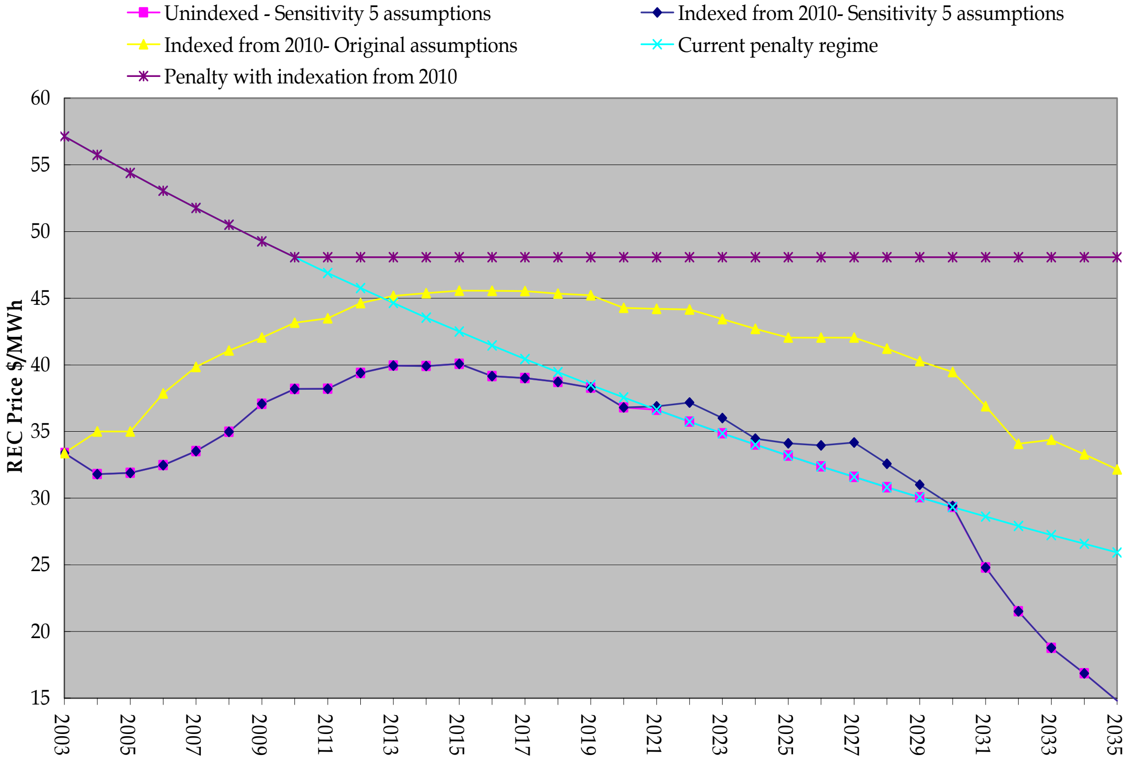
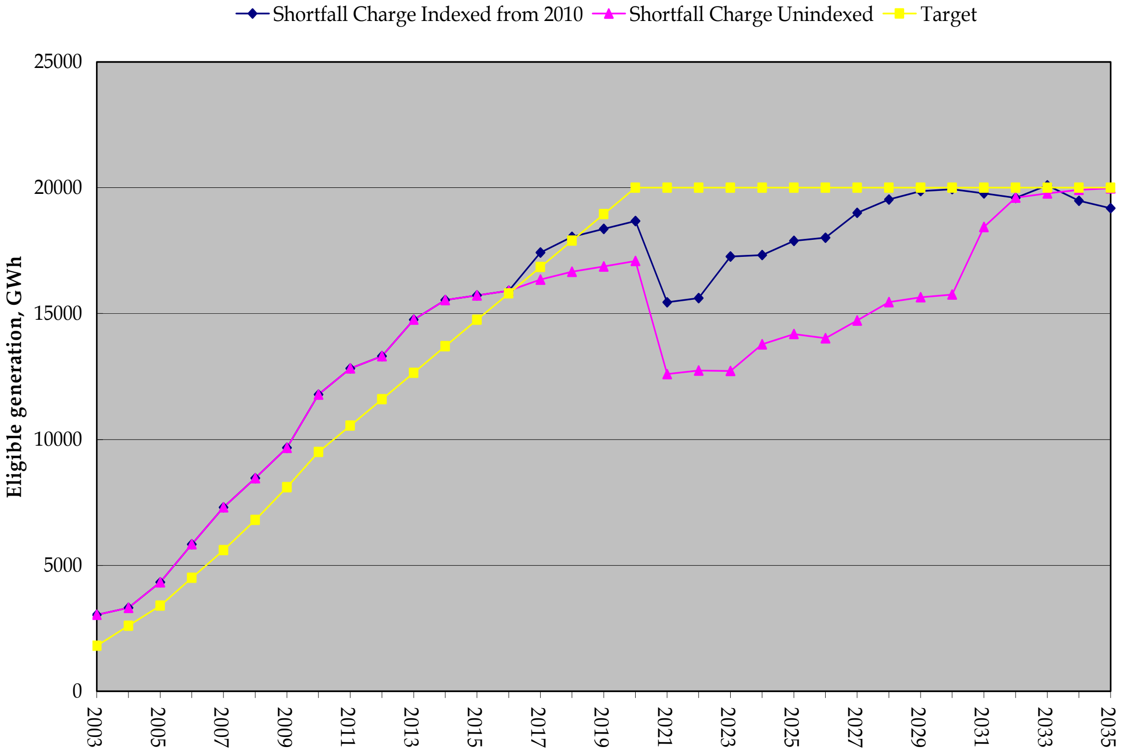


Figure 3.9: Eligible Renewable Generation for Sensitivity 5 (GWh)



4 CONCLUSIONS

In this study, the impact of a higher MRET target is forecast. The target increases from 9,500 GWh in 2010 to 20,000 GWh by 2020. If achieved this higher target would represent an increase in the level of renewable generation in 2020 of about 2.3% above 1997 levels, compared with around 0.6% in 2010 under the current MRET.

The key results of the analysis are that:

- With no indexation of the shortfall charge, the level of renewable generation is likely to be constrained. Although higher than would be achieved under the current target, the level of generation is still likely to be far short of the 20,000 GWh target proposed.
- With indexation from 2010, the target level of renewable generation is likely to be achievable, albeit at a higher compliance costs. In fact the level of renewable generation exceeds the target in the period beyond 2020, as renewable generator no longer eligible for certificates continue to operate.

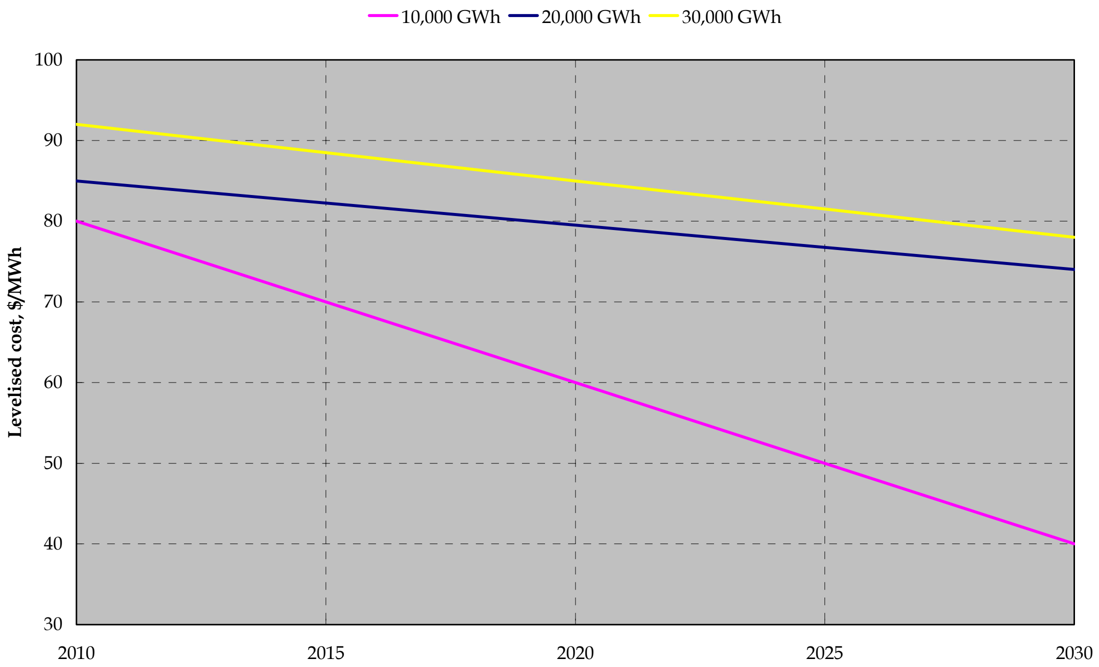
The results are driven by the fact that the renewable generation cost curve increases as the target increases due to lower wind yields, higher collection costs of biomass fuels and higher capital costs from resources being located at remote sites.

The need for some form of indexation to achieve the target may raise concerns about the long term sustainability of the renewable energy industry. This interpretation needs to be treated with caution. Although there is an initial increase in REC price, the downward trend in REC price post 2020, suggests that renewable energy generation will become more cost competitive in the medium term. Increasing the target requires more expensive renewable energy generation and this is the reason for the increase in REC prices over the period to 2015. For renewable generators already operating, the cost of generation is likely to fall to levels competitive with fossil fuel generation due to technology improvements and lower financing costs as the size of the industry grows.

For a given level of generation, the estimated reduction in the cost is shown in Figure 4.1. The levelised cost of the marginal generator required to meet a generation level of 20,000 GWh is projected to fall from $85/MWh in 2010 to

$74/MWh[10] in 2030 largely driven by a projected large decrease in the capital cost of wind generation in the period to 2015. Further evidence is provided in the modelling simulations by the continuing level of generation from renewable generators no longer eligible for certificates beyond 2020, suggesting that it will be economic for these generators to be replaced after the end of their operating life.

Figure 4.1: Estimates of the marginal cost of renewable generation at 10,000 GWh, 20,000 GWh and 30,000 GWh.



Estimates of the long run marginal cost of renewable generation is shown in Figure 4.2. The estimates indicate that by 2030, around 13,000 GWh of additional renewable generation will be competitive with fossil fuel generation as a result of a revised MRET measure[11]. Assuming lower renewable energy costs and higher cost for fossil fuel generation results in about 15,000 GWh of renewable generation becoming competitive. If a policy of zero emissions was adopted then the cost of fossil fuel generation would likely rise to about $50/MWh to $70/MWh, increasing the level of competitive renewable generation to between 20,000 GWh to 40,000 GWh.

The actual level of competitive generation is likely to be higher than indicated in Figure 4.2 as the marginal cost of renewable generation is compared with the average electricity price. Because of a favourable location

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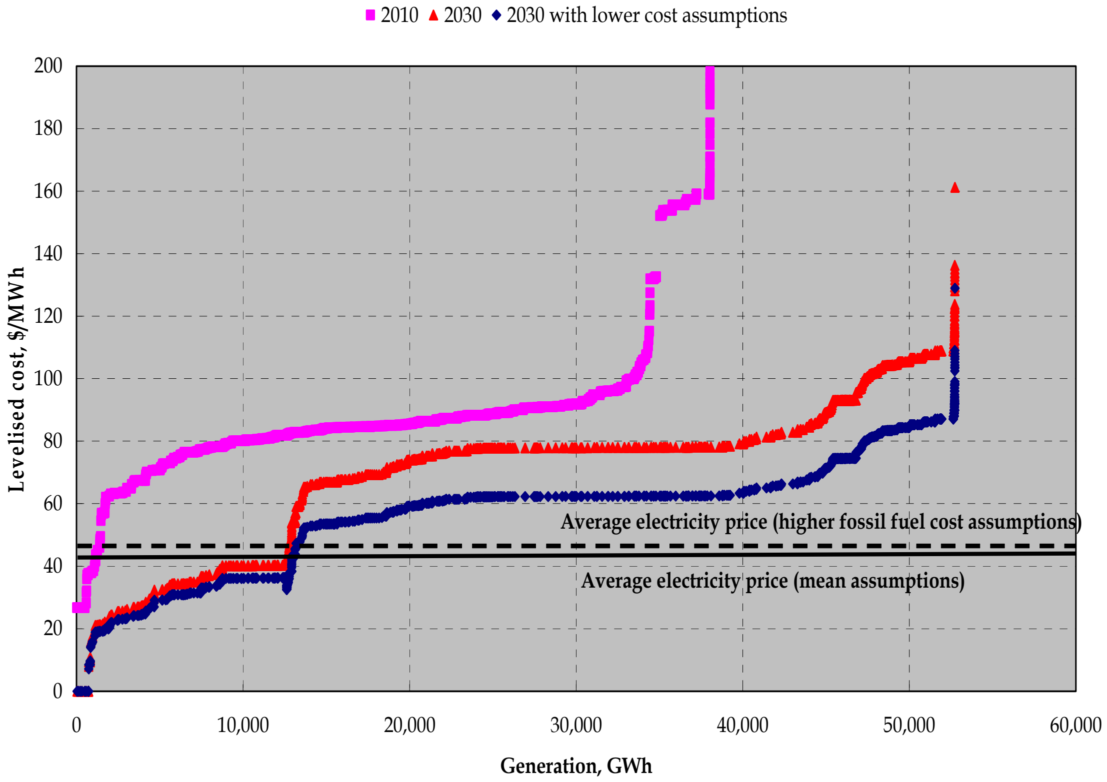
[10] The levelised cost represents the long run marginal cost of the last generator required to meet the target in mid 2003 dollar terms. It excludes revenue earnt from sales of electricity (that is , revenue from sales of electricity are not deducted from the costs)

[11] This is on top of the 16,000 GWh generated from renewable generators existing prior to 1997. Thus the total level of sustainable renewable generation is about 29,000 GWh.

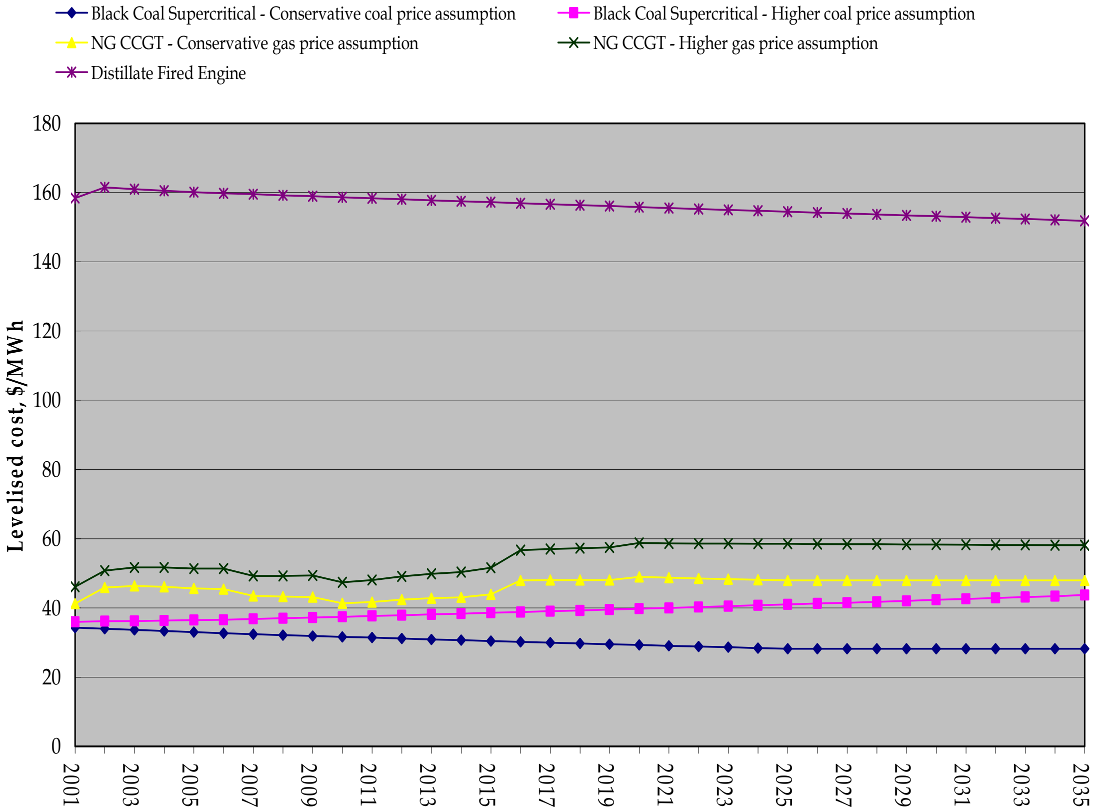
or a pattern of generation closely aligned to peak price periods, more renewable generation could be competitive with fossil fuel alternatives.

Figure 4.2: Cost curves for renewable generation



The analysis is based on conservative assumptions on fossil fuel generation costs and renewable technology costs. Plausible higher fossil fuel generation costs and lower renewable energy generation costs will likely see a higher level of renewable generation than estimated in this study. Higher fossil fuel generation costs would see the electricity price received by renewable generators increase by $3/MWh to $5/MWh for base load generation and up to $10/MWh for intermediate generation from 2015 onwards (see Figure 4.3). The higher cost of intermediate generation, if it eventuates, would favour those renewable generators that generate mostly in peak periods.

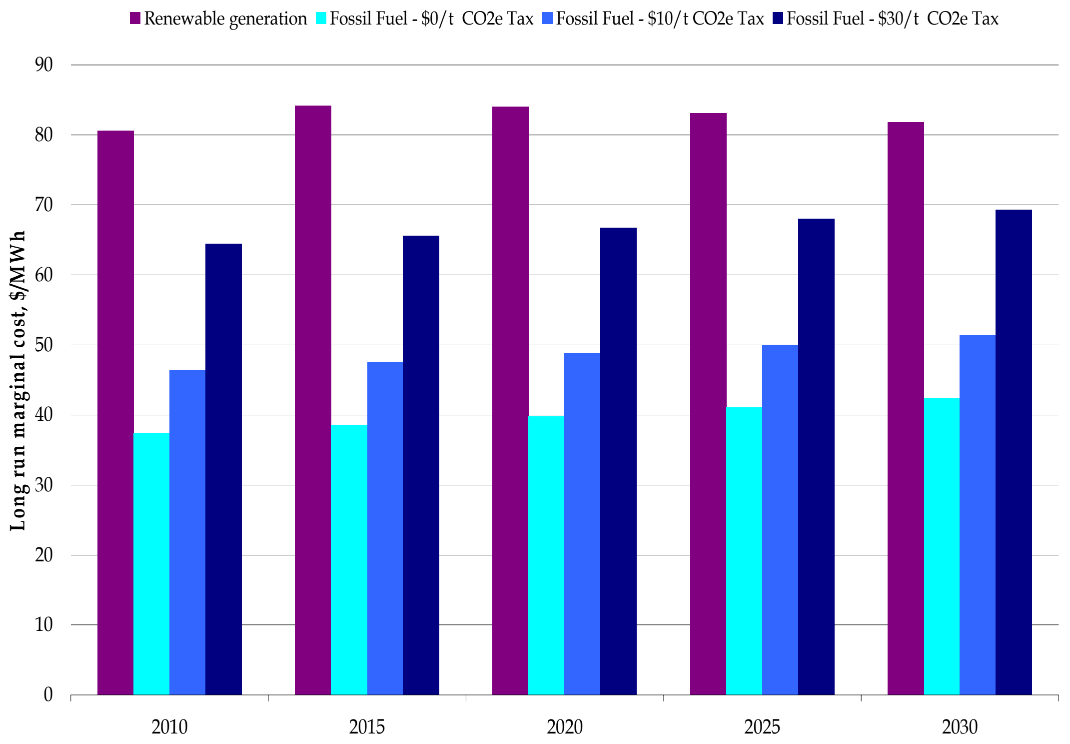
Figure 4.3: Fossil fuel generation costs, $/MWh



Assumes 9.22% WACC, 30 year life, conventional technology options, coal cost of 0.90/GJ in 2003.

Enforcement of more stringent greenhouse abatement measure will also likely see the price of fossil fuel generation increase to levels near renewable generation costs in the period from 2020 onwards (see Figure 4.4). Under the Panel's proposed target for renewable generation and the associated REC cost, a greenhouse gas emission impost of $10/t CO_2e would see the difference between renewable energy and fossil fuel generation costs fall to about $30/MWh in 2030. An impost of $30/t CO_2e would see the difference in generation costs fall to $12/MWh in 2030.

Figure 4.4: Generation costs with carbon dioxide emission imposts



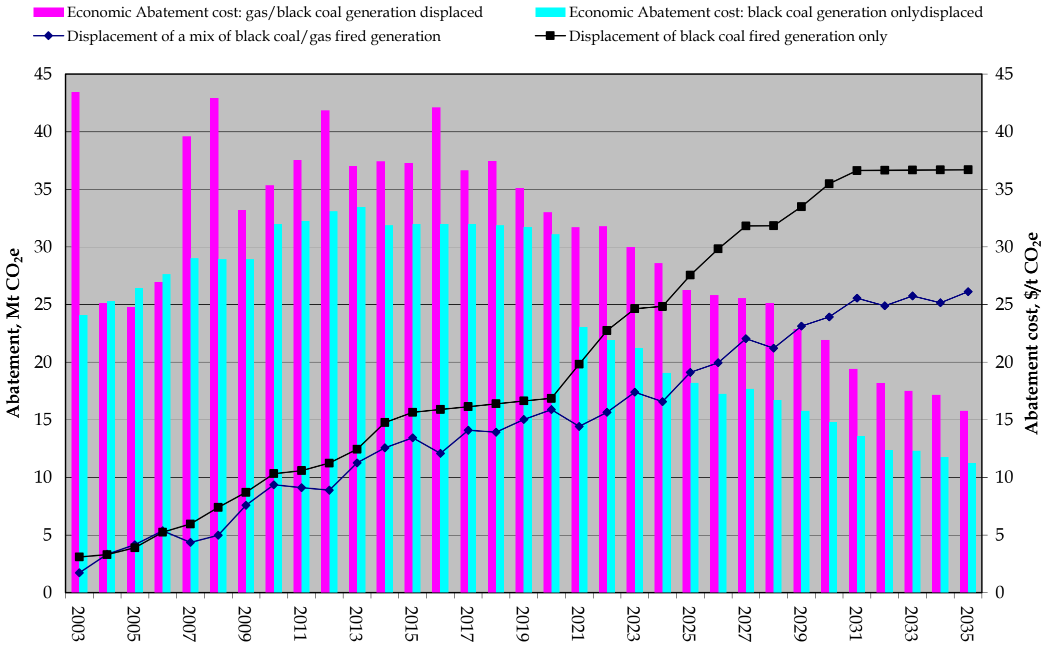
Note: Assumes conservative assumptions for renewable generation. The cost for renewable generation is the price of RECs required to meet the proposed target in each year plus the price of fossil fuel generation displaced by renewable generation.

Indexation may only be required for a short period. Examination of the results of the indexed scenario indicates that indexation would only be required to about 2020. Thereafter, no further indexation is required for the target level of renewable generation to continue to be achieved. Alternatively, indexation at a rate less than 100% of CPI may also achieve the higher target level of renewable generation.

Essentially, the key advantage of an increase in the target spread over a longer timeframe, even with a short period of indexation, is to provide the incentive to reduce costs and be competitive with fossil fuel generation.

The phased target increase also allows additional abatement in greenhouse gases relative to the current target of about 4 Mt to 7 Mt per annum over the period to 2020. Even further improvement could occur if only black coal generation is displaced rather than a mix of coal fired and gas fired generation (see Figure 4.5). This would also reduce the economy-wide abatement costs by about $5/t CO2e in the period to 2020 but up to $10/t CO2e difference from 2020.

Figure 4.5: Abatement of greenhouse emissions by renewable generation



Note: Based on the level of renewable generation and emissions for the indexed scenario.

The phased increase of the target also has other advantages. First, compliance costs are relatively modest compared with the cases where a high target is enforced for 2010 and thereafter remains steady. Compliance costs are about $2.03/MWh or about 2% of average electricity prices to end-users. Enforcing a 5% target by 2010 remaining at this level thereafter, which achieves a similar target of 20,000 GWh by 2020, results in compliance costs of about $2.50/MWh, an increase of about 23% compared to a similar 2020 target. Second, additions of new investments occur incrementally rather than upfront as is likely to occur with the current target and with increases to the target by 2010 remaining at that level thereafter. This increases the prospects for the development of sustainable renewable energy industry.