Report to

Sustainability Victoria

Assessment of Greenhouse Gas Abatement from Wind Farms in Victoria

July 2006

M M A

McLennan Magasanik Associates Pty Ltd
242 Ferrars Street
South Melbourne Vic 3205

Tel: (03) 9699 3977
Fax: (03) 9690 9881
Email: mma@mmassociates.com.au
Website: www.mmassociates.com.au

Ref: J1201 Report

TABLE OF CONTENTS

LIST OF TABLES

LIST OF FIGURES

EXECUTIVE SUMMARY

The Victorian Government has a policy of facilitating appropriate wind energy development. Activities range from the establishment of Policy and Planning Guidelines for commercial wind farms, increasing the quality and accessibility of publicly available information on Victoria's wind resources with the development of a Victorian Wind Atlas, and removing regulatory barriers to grid-connection through the introduction of a Wind Energy Development Act.

In November 2005, the Victorian Government also announced a commitment to investigate options for a market-based scheme to run in parallel with the MRET scheme to drive investment in renewable energy in Victoria. The Victorian Government said the aim of the Victorian Scheme was to drive investment in renewable energy in Victoria, including in wind generation. A public forum was held with stakeholders in December, and industry members were invited to review and provide comment on an Issues Paper.

There are benefits and costs associated with electricity generation from wind. The main benefit is the reduction in emissions of greenhouse gases. Wind generation will displace coal and gas-fired generation, resulting in a reduction of greenhouse gas emissions and emissions of other pollutants.

The extent to which wind generation in Victoria can reduce emissions of greenhouse gases is examined in this study.

Other benefits and costs have not been examined in this study.

The level of abatement from wind generation was estimated using a simulation model of the National Electricity Market (NEM). The model determines the dispatch of generating plant in order to meet electricity demand on an hourly basis. Plants are dispatched in order of ascending bids until demand is met in each hour.

Three scenarios were modelled:

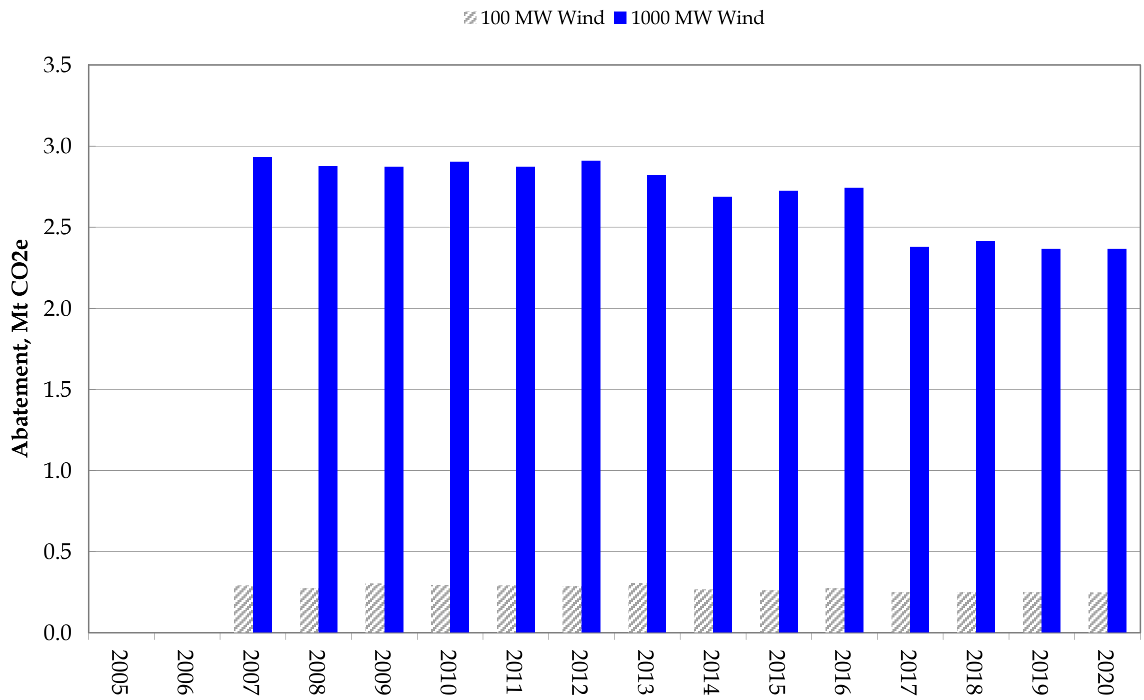
- No additional wind generation capacity in Victoria (apart from that already installed)
- 100 MW of additional wind generation, with the average capacity factor of the additional generation being 35%.
- 1000 MW of additional wind generation, with the average capacity factor of the additional generation being 33%.

The level of abatement was calculated as the difference in emissions between the scenarios with additional wind generation and the scenario without any additional wind generation.

Emissions included CO_2 emissions from combustion, CH_4 emissions occurring from the extraction and transport of fuels and CO_2 emissions from the processing of fuels.

The results of the analysis indicate abatement of between 0.25 and 0.31 million tonnes per annum for the 100MW case and between 2.4 and 2.9 million tonnes for the 1000MW case (see Figure 1).

Figure 1: Abatement of greenhouse gases with additional wind generation capacity



The abatement arises from the displacement of a mix of brown coal, black coal and natural gas based generation. The higher the level of wind generation, the more likely that high emission plant such as black coal and brown coal generation will be displaced. At low levels of wind generation, more aggressive bidding (towards marginal cost) by brown coal generators results in less of this generation being displaced (see below). At high levels of wind generation, some brown coal generation is displaced in off-peak periods as electricity demand and interconnector flow limits constrain the level of brown coal generation.

The average level of abatement (that is, the level of abatement per unit of electricity generated by wind) declines over time, as shown in Table 1.

Table 1: Average abatement intensity from wind generation, kt CO_2e/GWh

Wind Capacity	2007	2008	2009	2010	2011	2012	2013	2014	2015
100 MW	0.95	0.92	0.94	0.93	0.95	0.95	0.93	0.91	0.88
1000 MW	1.12	1.10	1.08	1.09	1.09	1.10	1.05	1.03	1.06

Source: MMA analysis

The average abatement is higher for the 1000 MW case than for the 100 MW case. Increasing the wind capacity reduces the level of gas-fired generation at first. But adding more wind generation results in proportionally more coal-fired generation being reduced, including some brown coal fired generation. With a 100 MW of wind only a marginal amount of brown coal generation is displaced (less than 0.2% of brown coal generation with no wind). With a 1000 MW of wind, around 600 GWh of brown coal generation is displaced per annum on average (representing about 1.3% of brown coal generation with no additional wind generation).

The results should be treated with some caution. The level of displacement of brown coal in the period up to 2012 reflects in part changes in bidding strategies by brown coal generators in order to support prices with excess generation as a result of 1000 MW of wind. More aggressive bidding (towards marginal cost) would result in slightly less brown coal generation being displaced. Over both the short and long term, the result reflects constraints in the ability of power to be exported into other States through interregional transmission network. Adding more transmission capacity between Victoria and other regions could reduce the impact on brown coal generation.

1 INTRODUCTION

Wind generation is set to expand in Victoria, based on the incentives provided by the MRET Scheme. Encouraging the use of renewable energy is also a key element of the Victorian Government's Greenhouse Challenge for Energy, with a specific policy to facilitate up to 1000 MW of wind generation in environmentally acceptable locations, and to increase the share of Victoria's electricity consumption from renewable sources to 10% by 2010. In November 2005, the Victorian Government also announced a commitment to investigate options for a market-based scheme to run in parallel with the MRET scheme to drive investment in renewable energy in Victoria. The Victorian Government said the aim of the Victorian Scheme was to drive investment in renewable energy in Victoria, including in wind generation.

Wind generation in Victoria will provide benefits and costs. One benefit is the abatement of greenhouse gas emissions. MMA has been engaged by the Sustainability Victoria (SV) to provide an estimate of the abatement of greenhouse gas emissions with extra wind capacity installed in Victoria. Additional renewable energy will substitute for fossil fuel generation, with the mix of fuel displaced (black coal, brown coal and natural gas) depending on the pattern of wind generation. Estimates of the level of abatement are derived by using a simulation model of the National Electricity Market, which determines the fossil fuel displaced by the wind generation.

2 METHOD AND ASSUMPTIONS

The Policy and Planning Guidelines for the development of wind energy facilities in Victoria contain calculations for the greenhouse benefits of wind farms. The assumption is that for every megawatt hour (MWh) of renewable energy generated, the emission of approximately 1.3 tonnes of carbon dioxide (CO2) would be displaced. This is derived from the electricity pool coefficient, which is the average of the greenhouse emissions per unit of electricity generated from the mix of generators contributing to Victoria's electricity supply.

However, this may not necessarily be the case. With the electricity grid extending over several States, it is possible that increased levels of renewable generation may displace largely black coal generation in other States. Natural gas fired generation in Victoria may also be displaced during peak demand periods, when the level of demand in Victoria is likely to be in excess of the capacity of brown coal generation.

Thus, a more sophisticated approach is required to estimate the level of abatement from wind generation. The approach taken to estimating the impacts and the estimates of abatement are outlined in this Section.

2.1 METHOD

In this study, the level of abatement and the impact on fossil fuel generation from wind generation is estimated. Abatement of greenhouse gas emissions is estimated for a time period from 2005 to 2020. Both average levels of emissions over each year and the marginal rate of abatement in each hour of the year are estimated. The average level of abatement provides a general guide of the abatement in each year from wind generation. The marginal abatement can be used to provide estimates to the level of abatement from individual wind farms with a particular generation profile.

The abatement from wind generation is measured for the following three scenarios:

- Base case: with no additional wind generation (apart from already installed capacity). This case is used as a benchmark to estimate impacts.
- With 100 MW of additional wind generation.
- With 1000 MW of additional wind generation.

2.1.1 Market simulations

Emission abatement is estimated using MMA's National Electricity Market model based on the Strategist probabilistic market modelling software licensed from New Energy Associates. Strategist represents the major thermal, hydro and pumped storage resources as well as the interconnections between the NEM regions. In addition, MMA partitions Queensland into four zones to better model the impact of transmission constraints and losses on trends in the marginal loss factors across Queensland.

Average hourly pool market outcomes are determined within Strategist based on thermal plant bids that are derived from marginal costs or entered directly.

The approach is described in the following charts. Figure 2-1 shows the Strategist methodology and Figure 2-2 shows how we use it by changing timing of generation and transmission and bidding strategies.

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

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

Figure 2-1 Strategist Analysis Flowchart

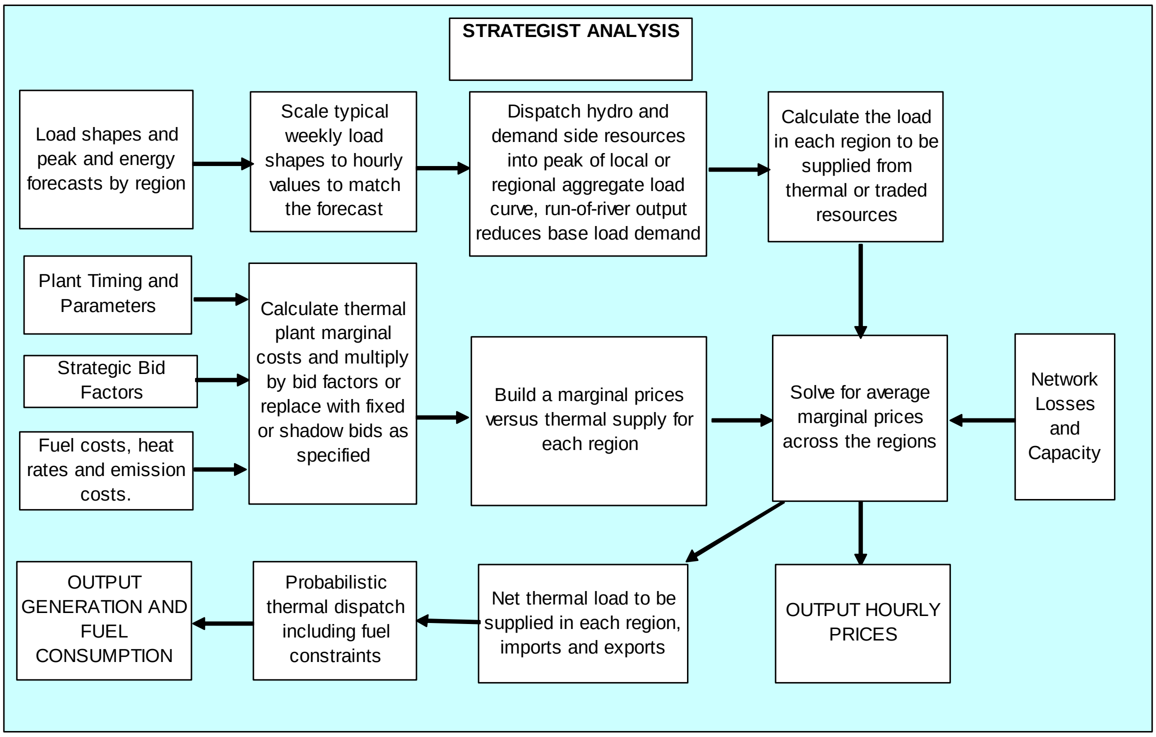
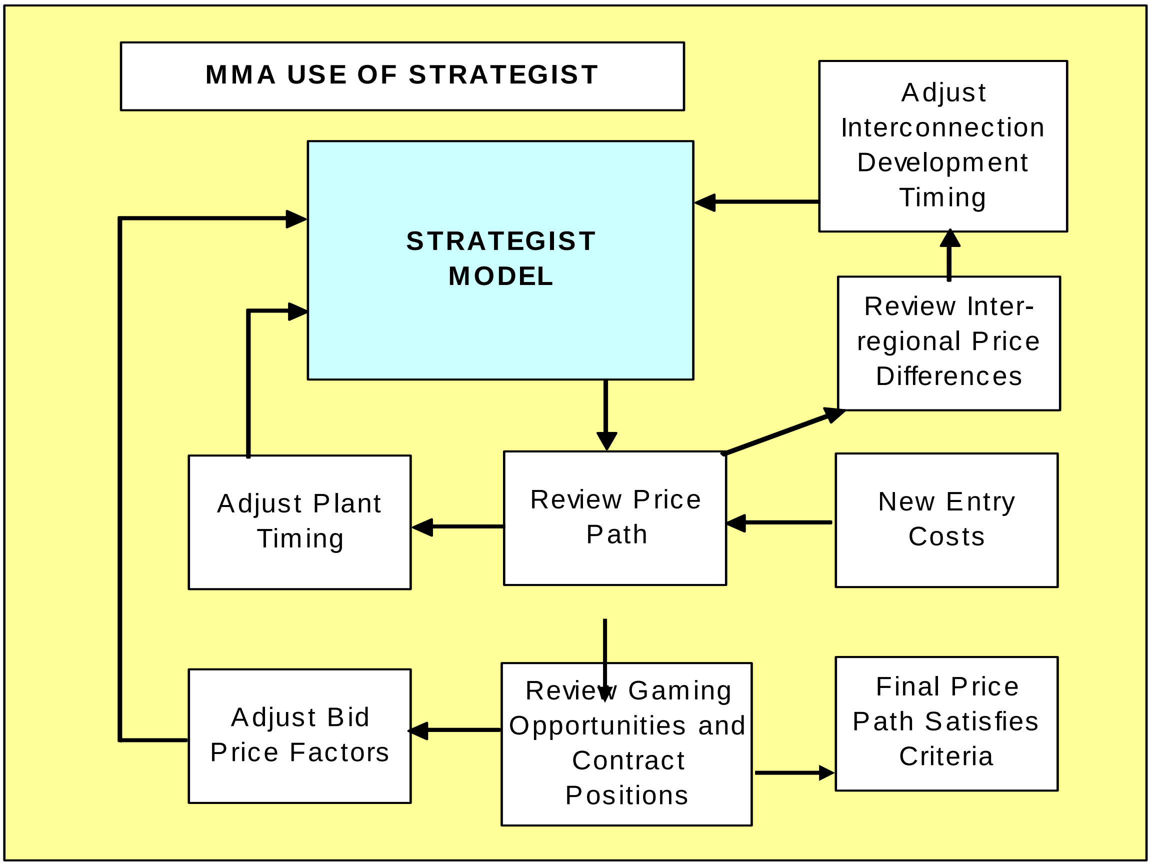


Figure 2-2 MMA Use of Strategist

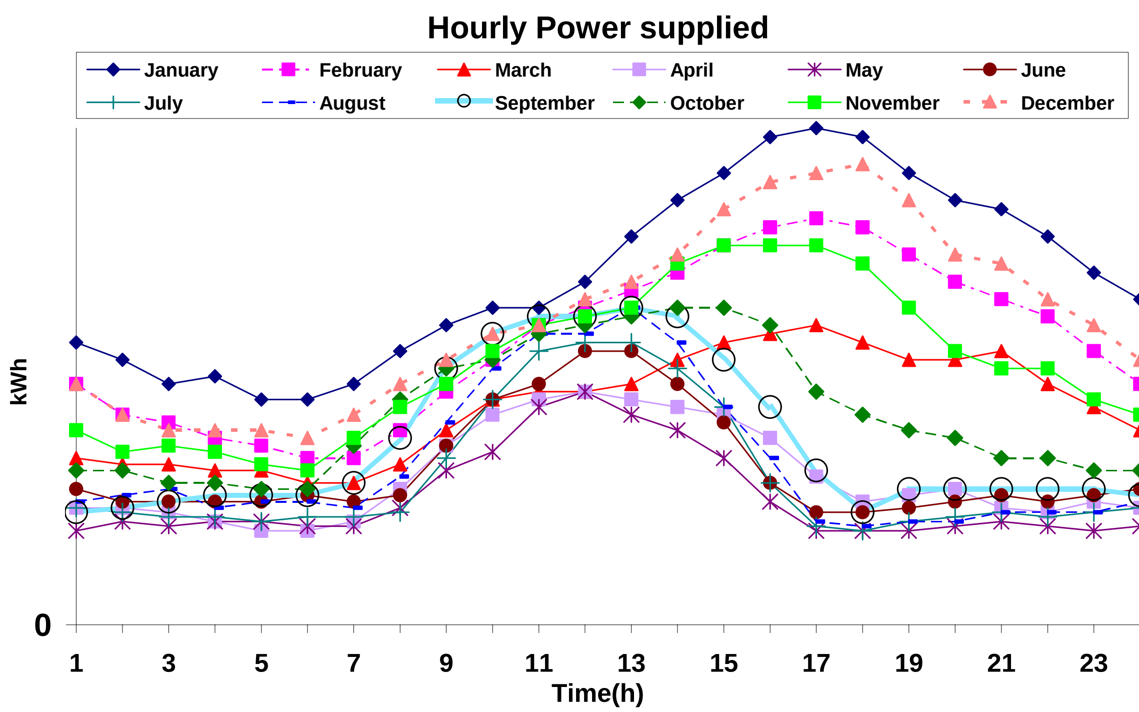


2.1.2 Modelling of wind generation

Wind farm generation in the market simulation model is modelled as a typical profile of energy availability. Typical daily generation profiles are used to represent the level of wind generation in each hour of a typical day in each month. Daily generation patterns were modelled using historical load profiles obtained from published data mainly from wind generation data for the Breamlea wind farm.

The typical daily generation patterns for each month of the year are shown in Figure2-3. These typical wind generation patterns average wind generation levels for each hour of the day in each month. The profiles are adjusted to obtain an average annual capacity factor of 37% for existing wind capacity to 33% for 1000 MW of wind farms. The decline in capacity factor reflects the fact that less windy sites are likely to be used at higher levels of wind generation.

Figure2-3: Assumed daily wind generation patterns



In the Strategist simulation model, reliability of wind generation was modelled using the ratio of maximum to minimum capacity. International and domestic data on firm capacity for existing wind generators was applied after adding 100MW and 1000MW. Minimum capacity was set at an estimate of the firm level of wind generation – assumed to be 15% in this exercise. That is, 15% of the total capacity of wind generation was assumed to be firmly available at all times and could be relied upon to provide capacity during peak periods. The intermittency of wind generation was modelled using an availability factor of 33% (that is, the model assumed that the probability of the capacity of wind generation being fully available in any one hour is 33%) for the 1000MW case, 35% for the 100MW case and 37% for the existing capacity case.

2.1.3 Emissions modelling

Both combustion and fugitive emissions are considered in this study. Emissions by state were extracted for CO_2 emitted during combustion, fugitive CO_2 released during processing of natural gas, and fugitive CH_4 emissions from transport of natural gas and mining of coal. Fugitive CH_4 emissions are converted into CO_2e by multiplying by 21.

The combustion emission intensities employed in the current study are presented in Table 2-1, on an emission per unit of fuel energy for each of the fuel types used.

Greenhouse gas emissions from the combustion process result from the conversion of carbon in the fuel to CO_2. The key parameters in determining the CO_2 emissions are therefore the quantities and types of fuel fired and the carbon content of the relevant fuels. Carbon contents and combustion emission intensities for each different coal and gas supplying generating facilities have been identified and incorporated into the electricity model. Emission intensities on the basis of individual power stations are supplied in the National Greenhouse Gas Inventory (NGGI) for years up to 2002 and these have been used as defaults where no further information could be found.

Emission intensities have been estimated under the same assumptions used in the NGGI. In particular:

- The fraction of carbon in the fuel that is emitted as CO_2 and not sequestered in ash and solid fractions is 99%.
- The emission of CO_2 per unit fuel consumption is dependent only on the carbon in the fuel and is not related to the equipment used to burn the fuel.

The practice of co-firing biomass fuels in conventional coal-fired generators, such as is occurring at Liddell in NSW, has been accounted for through a reduction in the carbon intensity of the fuel at the generator in question.

Emission intensities will vary over time as the coal properties in the seams being mined vary. They will also vary as mines supplying the stations close and supply is sourced from elsewhere. The historical emission factors reported in the NGGI indicate that these may vary by a few percent for a given power station. This data does not indicate any particular trends in these changes and it is unlikely that projection of intensity on this basis would be reliable. The only changes in emission intensities likely to be able to be accounted for are those resulting from changes in the coal supply to a particular power station. These have been modelled where information is available.

Emission intensities for combustion CO_2 were defined in units of Gg/GJ of fuel burnt, using the latest emission rates from the NGGI. The emission rates were allocated for each fuel used in the study. The model does not model the supplementary fuel burn so the associated emissions were incorporated into the primary fuel emission intensities.

Table 2-1: Emission intensities – NEM

Fuel	Combustion CO_2 (kg CO_2 e/GJ)	Fuel type
Loy Yang	92.48	Brown coal
Morwell	92.16	Brown coal
Yallourn	98.77	Brown coal
Anglesea	86.33	Brown coal
Leigh Creek Coal	92.10	Brown coal
Bayswater	87.60	Black coal
Eraring	86.16	Black coal
Vales Point	89.10	Black coal
Mt Piper	88.40	Black coal
Liddell	87.30	Black coal
Wallerawang	87.50	Black coal
Munmorah	89.30	Black coal
Ipswich Basin	83.47	Black coal
Meandu	91.35	Black coal
Callide	94.55	Black coal
Curragh	92.10	Black coal
Bowen Basin coal	89.95	Black coal
Collinsville	89.40	Black coal
Millmerran	86.68	Black coal
Kogan Creek	86.68	Black coal
Washery Waste Coal	88.56	Black coal
Coal Seam Methane	50.80	Gas
Bass Strait Gas	50.90	Gas
Bairnsdale	50.90	Gas
Cooper Basin Gas	50.80	Gas
Ladbroke	50.80	Gas
PNG Gas	51.20	Gas
Distillate/LFO	68.90	Oil

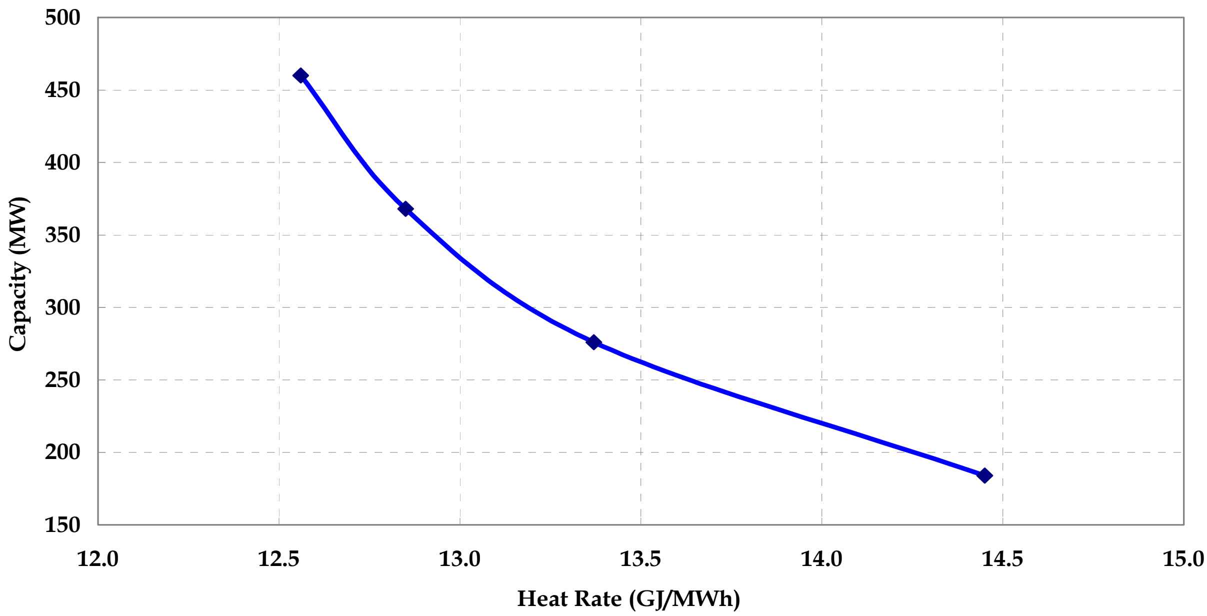
Source: AGA (2000), *Assessment of Greenhouse Gas Emissions from Natural Gas;* National Greenhouse Gas Inventory; National Greenhouse Gas Inventory (2000), *Workbook for Energy (Fuel Combustion*", Workbook 1.1, Supplement, NGGIC.

Emissions of CH_4 and N_2O during combustion are handled by applying emission intensities for these gases to electricity generation by power plant. Emission intensities on a kt/GWh basis were derived from historical data provided in the NGGI (2002). Average intensities were applied by technology type.

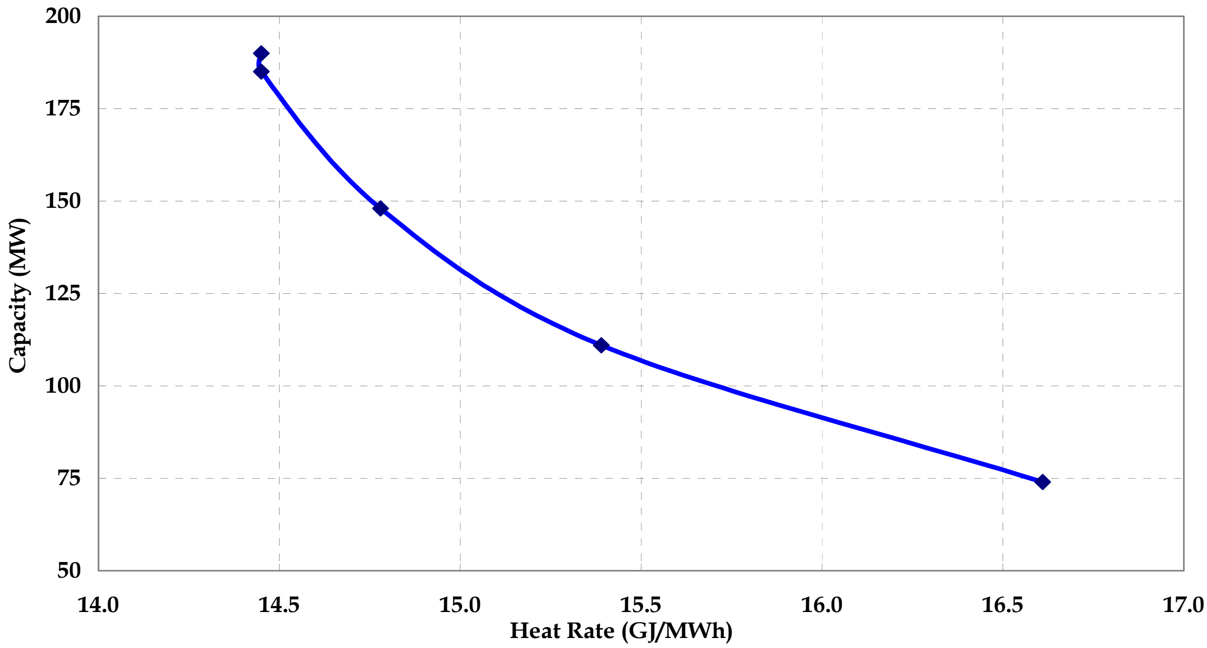
Another factor explicitly incorporated into the simulation modelling is the level of operation of the fossil fuel generators. Emission intensity increases when fossil fuel generating plant operates at lower capacity, which may partly compensate for some of the abatement attributable to wind generation. The simulation model explicitly incorporates efficiency curves for each generating plant. The curves depict the thermal efficiency (that is, the amount of electricity sent out for each unit of fuel consumed) as a function of the capacity of the plant. The curves for representative brown coal plant are shown in Figure 2.4.

Figure 2-4: Efficiency curves for brown coal generation

(a) Loy Yang A



(b) Hazelwood



2.2 MARKET ASSUMPTIONS

The simulation model is structured to produce hourly outcomes over the estimation period. There are a large number of uncertainties that make assessing impacts difficult. For all scenarios modelled, market assumptions reflect the most probable outcomes given the current state of knowledge of the market. The analysis is based on medium energy growth as well as median peak demands, as provided by NEMMCO, which are dependent on weather in the peak seasons.

Key market assumptions include:

- The medium demand growth projections with annual demand shapes consistent with the relative growth in summer and winter peak demand.
- The Queensland Cleaner Energy Policy and New South Wales Emission Benchmark Schemes remains in place.
- PNG/Timor Sea gas supply delivered to Queensland for new power generation from January 2012.
- Generators behaving rationally, with uneconomic capacity withdrawn from the market and bidding strategies limited by the cost of new entry.
- The assumed generator bidding profiles reflect generator contracting levels.
- Basslink commences operation in May 2006.
- The Commonwealth Government's policy to achieve 2% additional renewable energy by 2010 has been implemented as a 9,500 GWh target with a maximum penalty for

non-performance of $40/MWh. Only 400 MW of the 1000 MW target in Victoria is assumed to be commissioned to meet the MRET target (the additional 600 MW is assumed to be encouraged through either Green Power sales or through State Government incentives).

- The commissioning of Snowy Hydro's Laverton open cycle gas fired power station in 2006.
- The commissioning of Kogan Creek as a base load generator in Queensland in November 2008.

Other detailed assumptions are included in Appendix A.

3 RESULTS

3.1 ESTIMATES OF ABATEMENT

Estimates of the average abatement per unit of electricity are shown in Figure 3-1. With a 100 MW of wind capacity in Victoria, the average level of abatement is estimated to be between 0.93 kt CO_2e/GWh to 0.95 kt CO_2e/GWh in the period to 2013. Thereafter, the average level of abatement falls steadily to be just above 0.80 kt CO_2e/GWh. With a 1000 MW of wind, the average level of abatement falls to around 1.09 kt CO_2e/GWh in 2013. Thereafter, the average level of abatement falls steadily to level out around 0.97 kt CO_2e/GWh.

Figure 3-1: Average abatement intensity from wind generation, kt CO_2e/GWh

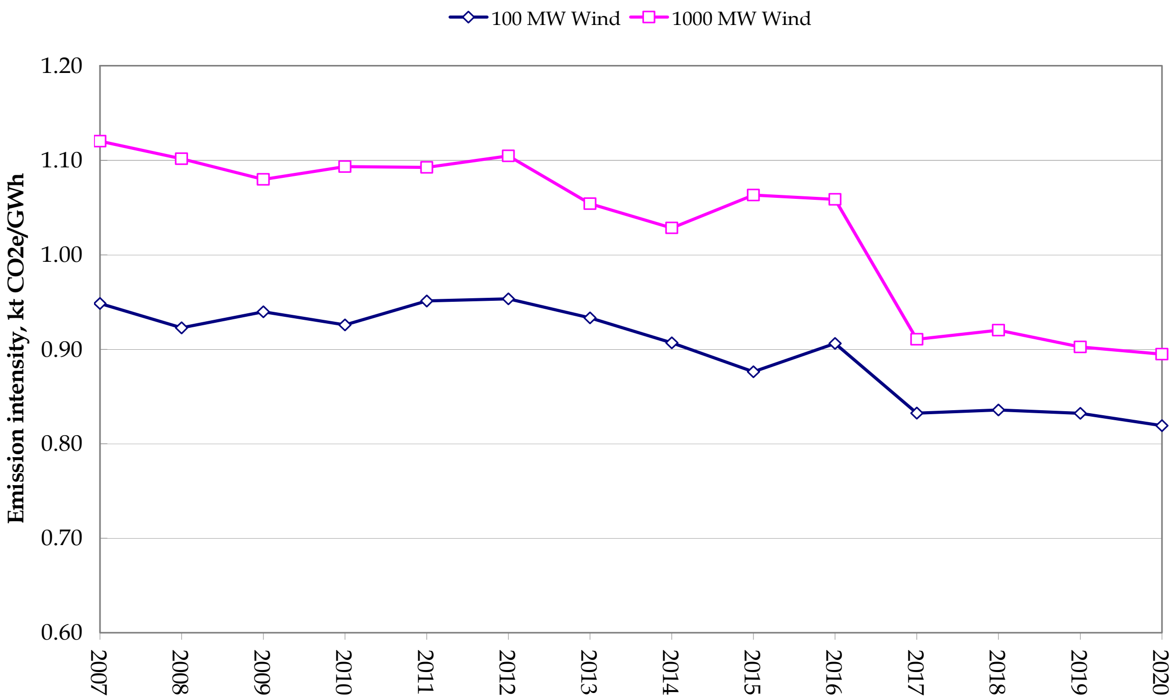


Table 3-1: Average abatement intensity from wind generation, kt CO_2e/GWh

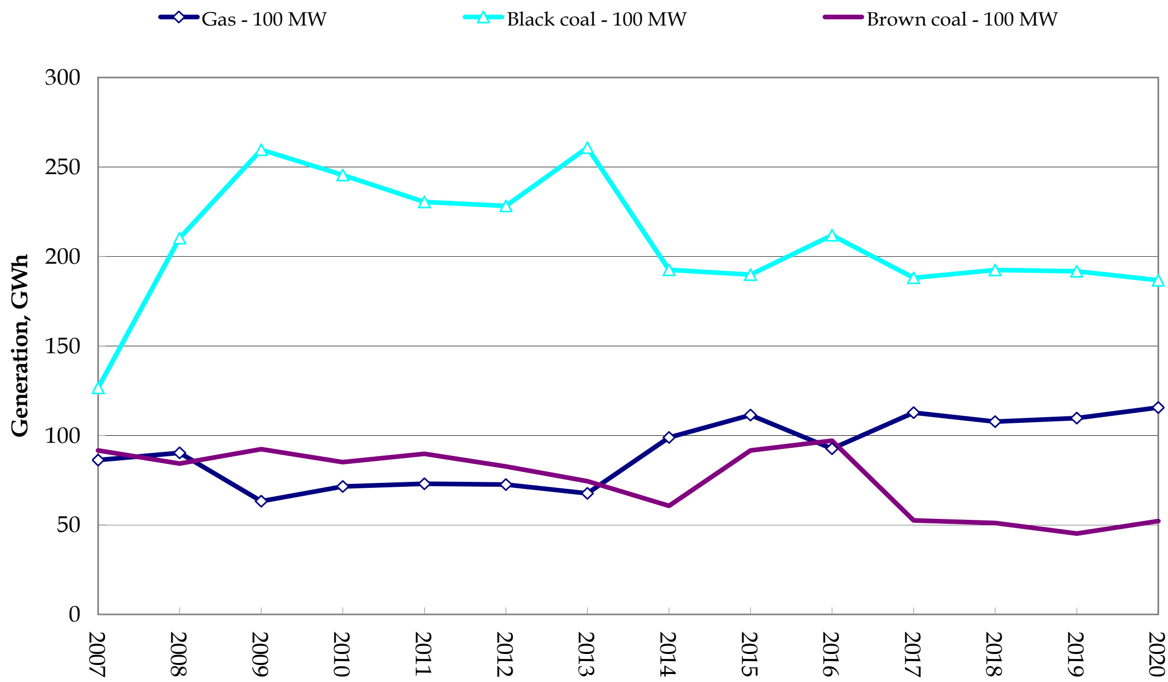
Wind Capacity	2007	2008	2009	2010	2011	2012	2013	2014	2015
100 MW	0.95	0.92	0.94	0.93	0.95	0.95	0.93	0.91	0.88
1000 MW	1.12	1.10	1.08	1.09	1.09	1.10	1.05	1.03	1.06

The average abatement is higher for the 1000 MW case than for the 100 MW case. Increasing the wind capacity reduces the level of gas-fired generation at first. But adding more wind generation results in proportionally more coal-fired generation being reduced, including some brown coal fired generation (see Figure 3-2). With a 100 MW of wind only a marginal amount of brown coal generation is displaced (less than 0.2% of brown coal generation with no wind). With a 1000 MW of wind, around 600 GWh of brown coal generation is displaced per annum on average (representing about 1.3% of brown coal generation with no wind).

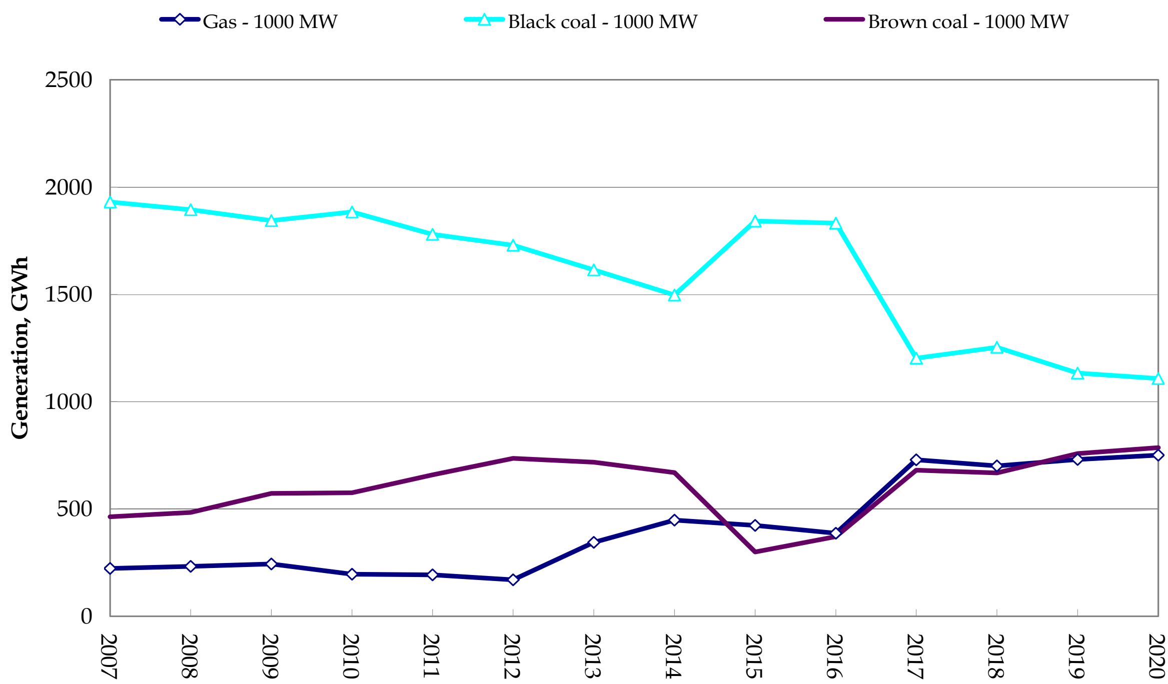
Note that in some years, the average level of fossil fuel generation displaced is slightly higher than the level of additional wind generation. This is because wind generation in Victoria, to the extent that it generates in peak periods, will displace imports of electricity from other States. Imports incur high transmission losses and these are avoided by high levels of wind generation.

Figure 3-2: Displacement of fossil fuel generation by fuel type, GWh

(a) 100 MW of wind generation



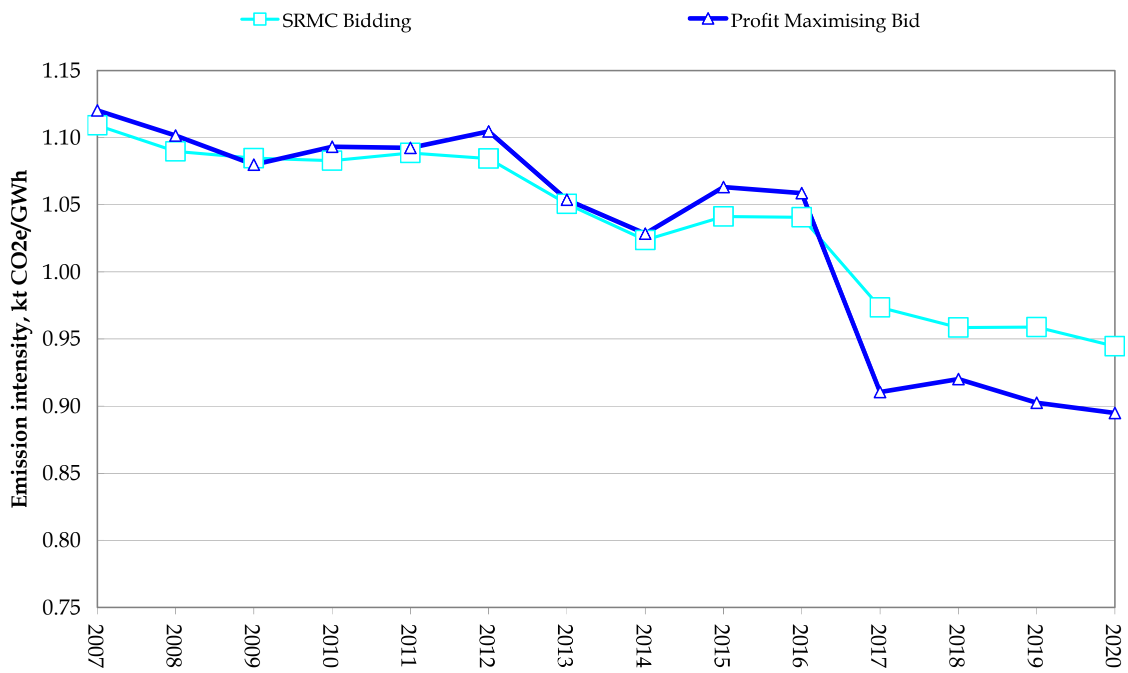
(b) 1000 MW of wind generation



The impact on brown coal generation should be treated with some caution. The level of displacement of brown coal in the period up to 2012 may reflect changes in bidding strategies by brown coal generators in order to support prices with excess generation as a result of 1000 MW of wind. More aggressive bidding (towards marginal cost) could result in less brown coal generation being displaced. To test this, we undertook a sensitivity with all brown coal plant bidding at short run marginal cost for the 1000 MW wind case. The emission intensities where only slightly different (less than 5% in the period up to 2015) and in some years where even higher due to losses on higher levels of exports to other regions.

This results suggests that the relatively high average emission intensity is due to the fact that brown coal plant are being offloaded in some periods of the year – mainly in off-peak periods when there is high level of wind generation. To illustrate this, Figure 3-4 shows the assumed demand profile (50% percentile) for Victoria for a typical week in February 2010, with the export potential added in each hour, as the shaded area. The black solid line represents total sent out capacity of brown coal capacity plus wind capacity in each hour. If this line is below total demand in an hour, this implies that brown coal plants are likely to be fully utilised in that hour. If the line is above total demand in an hour, then some of the brown coal plant capacity is likely to be off-loaded in that hour. The light line represents the potential wind capacity for each hour. Two cases are presented: 330 MW in every hour representing the average level of wind generation for 1000 MW of wind in Victoria; and 1000 MW in every hour representing the peak level of wind generation for 1000 MW of wind in Victoria.

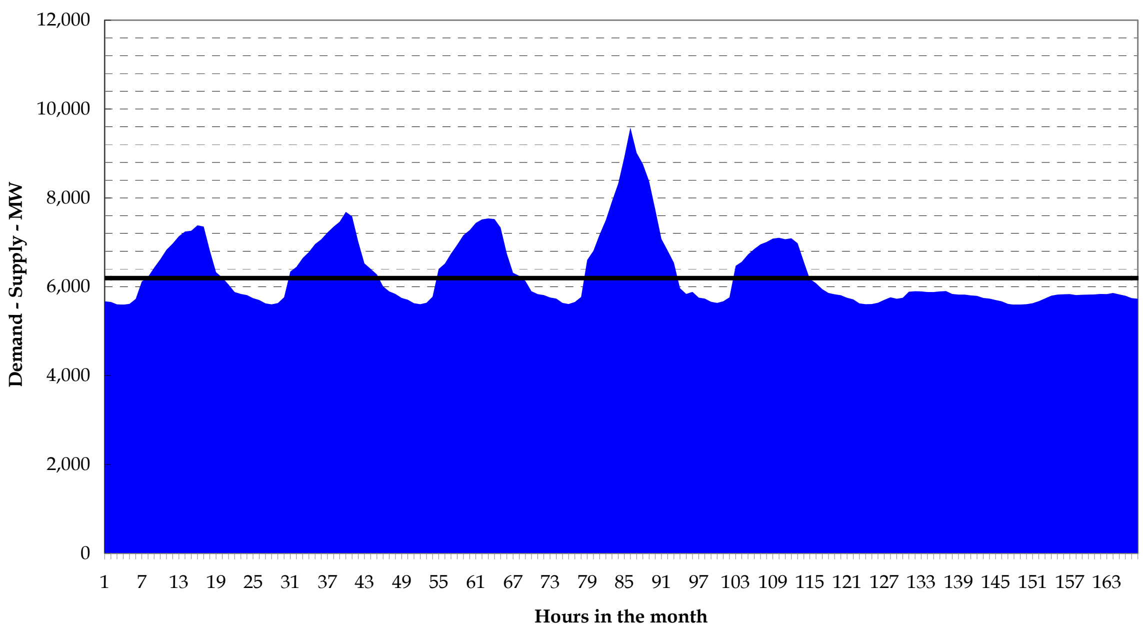
Figure 3-3: Sensitivity of average emission intensity to bidding strategies of brown coal generators, 1000 MW wind scenario, kt CO_2e/GWh



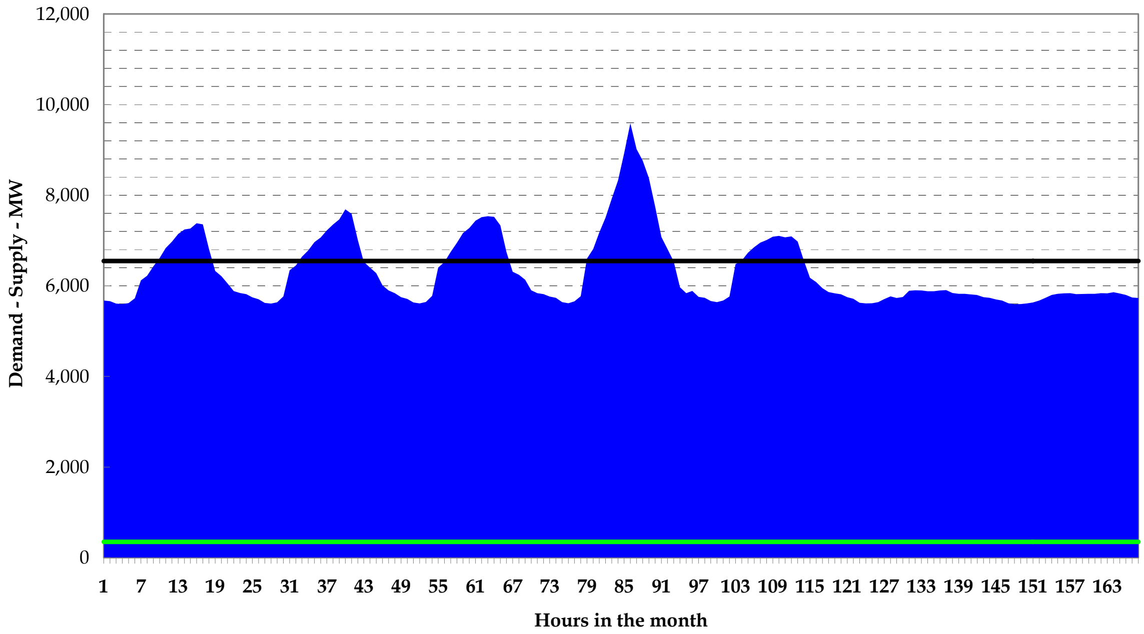
The Figures illustrate support the simulation results that brown coal plant are likely to be off-loaded more often with a 1000 MW of wind, particularly during off-peak periods.

Figure 3-4: Illustration of potential for off-loading of brown coal plant by wind generation

(a) Victorian electricity demand (plus exports) and no wind generation



(b) Victorian electricity demand (plus exports) and 330 MW average wind generation in each hour



(c) Victorian electricity demand (plus exports) and 1000 MW peak wind generation in each hour

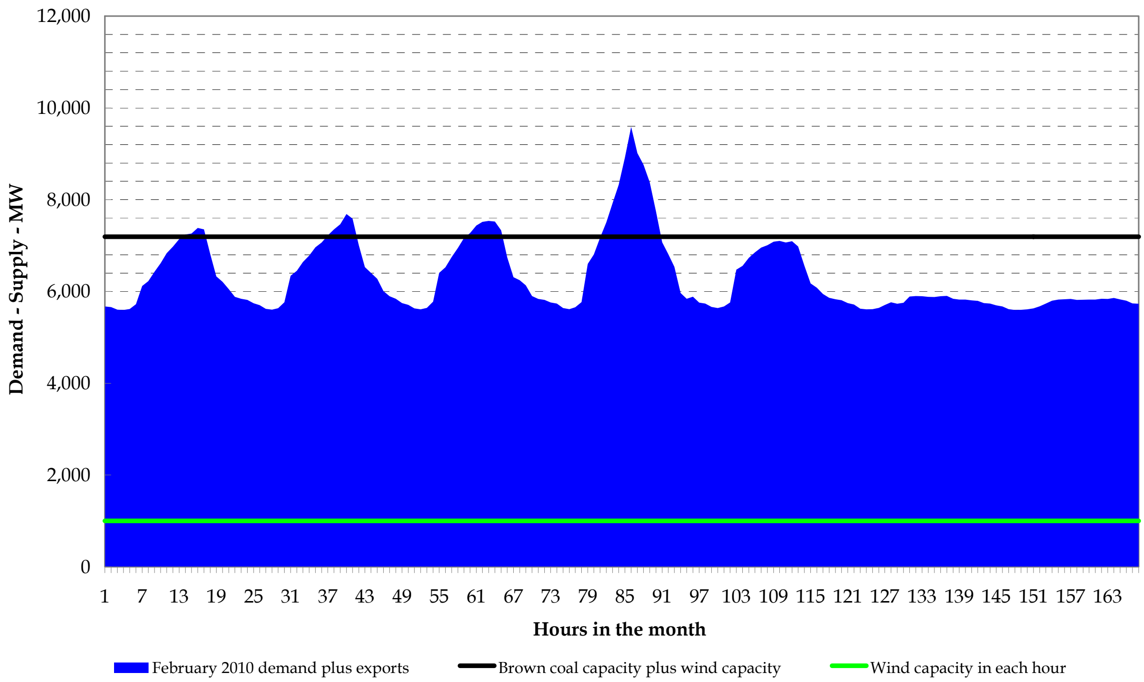
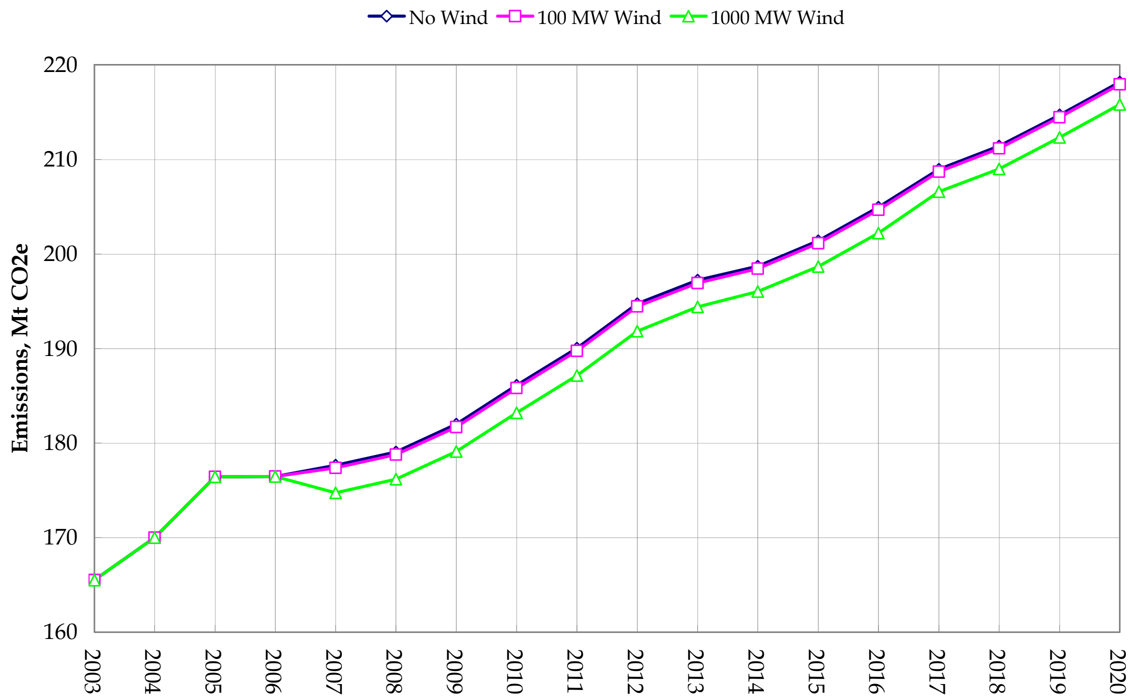


Figure 3-5: Emissions of greenhouse gases from electricity generation in the NEM



The high emission intensity could also reflect the fact that over both the short and long term there may be constraints in the ability of power to be exported into other States through interregional transmission network. Adding more transmission capacity between Victoria and other regions could reduce the offloading of brown coal generation and thereby reduce the emission intensity.

Nonetheless, displacement of brown coal generation is likely to be less if the additional wind capacity was located in other States. Therefore, it is likely that locating wind generation in Victoria rather than in some other States would result in slightly more abatement.

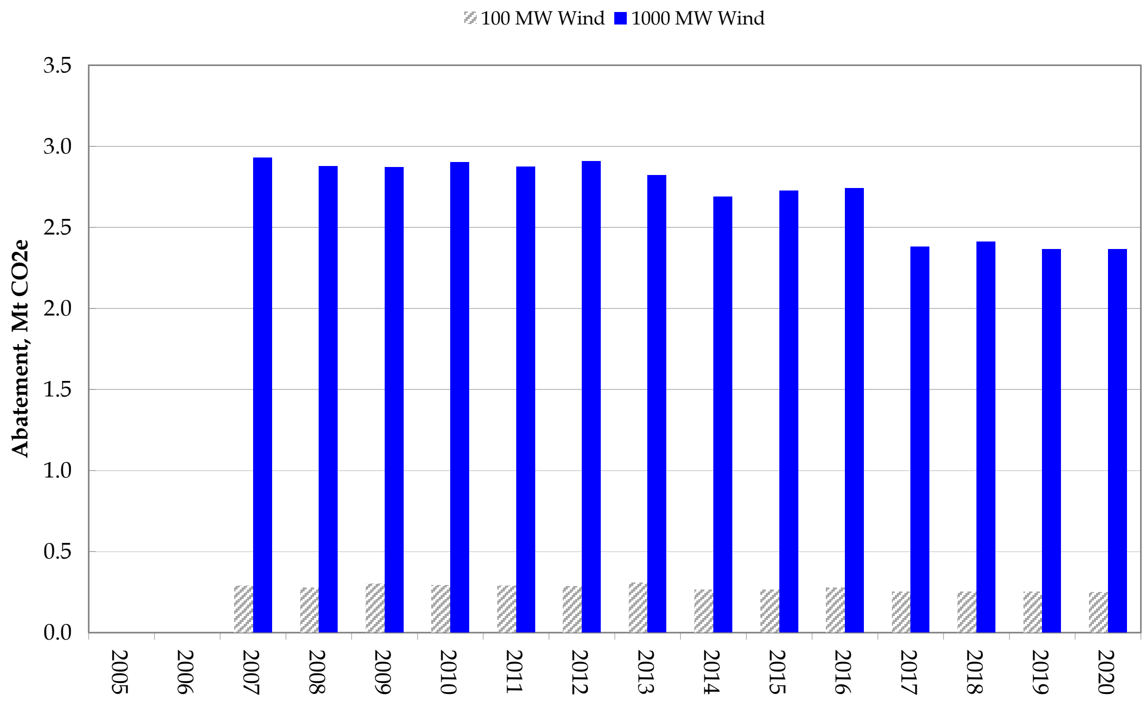
Victoria contributes between 32% of total emissions in the NEM at the start of the period to 28% of total emissions by the end of the study period. This is because of the savings from wind displacing coal and gas fired generation in Victoria, whereas relatively more new plants may be commissioned in NSW and Queensland as no new renewable energy has been modelled in other states.

For both the 100 MW and 1000 MW cases the emission intensity falls over time. This reflects the fact that the wind generation displaces more gas-fired generation over time, in particular deferring the need for new gas plant. However, some gas-fired generation is still required to ensure reliability of supply. The results also arise because new more efficient coal plants are also deferred as a result of more wind generation.

Savings amount to between 0.25 and 0.31 million tonnes of carbon dioxide abatement for the 100MW case and between 2.4 and 2.9 million tonnes for the 1000MW case (see Figure

3-6). This represents around 0.1% of total emission from electricity generation in the NEM for 100 MW of wind generation to 1.4% of total emissions for 1000 MW of wind.

Figure 3-6: Abatement of greenhouse gases with additional wind generation capacity



Note that modelling the level of abatement was confined to an additional 100 MW and 1000 MW of wind generation. For levels of generation between 100 MW and 1000 MW, an approximate estimate of the level of abatement can be made by taking a linear interpolation between the abatement estimates for 100 MW and 1000 MW. For example, with 200 MW of wind generation, the level of abatement would approximately be 0.5 to 0.6 million tonnes per annum.

3.2 LIMITATIONS AND UNCERTAINTIES

The modelling represent a rigorous attempt at obtaining more accurate estimates of the emissions abated from higher levels of wind generation. The estimation method takes into account factors not typically incorporated in previous modelling. These factors include:

- Realistic representation of the generating plant likely to be displaced by wind generation by taking into account the economic interactions between generating plant in the NEM.

- Taking into account the different fuels operated by each generating plant and the differing emission intensities of the fuels.

- Taking into account the fact that different operating levels of plant will result in different emission intensities. Thus, the fact that coal-fired plant may be operated at lower capacities as a result of wind generation has been explicitly modelled.
- Taking into account the full fuel cycle in determining emission intensities by fuel.

Nonetheless, there are a number of uncertainties in the method employed. First, a typical pattern of wind generation over the year was employed. The actual pattern of wind generation may differ, which could result in slight differences in the mix of plant displaced. The actual capacity factor may also differ from the levels assumed in the analysis, although it would require large changes in the capacity factor of wind farms to see material changes in emission intensities. Second, more aggressive bidding by brown coal generators will reduce the level of emission saved. Third, there is no account for the fact that a higher cost of electricity as a result of higher levels of renewable generation may result in a small reduction in electricity demand, thus reducing emissions even further.

4 CONCLUSIONS

An increase in wind capacity in the Victorian region will certainly reduce greenhouse gas emissions. In the period to 2015, the level of abatement averages between 0.88 kt CO_2e/GWh to 1.12 kt CO_2e/GWh. This results in an annual average abatement of about 0.3 Mtpa for 100 MW of wind generation and 2.6 Mtpa for 1000 MW of wind generation[1].

The results should be treated with some caution. The level of displacement of brown coal in the period up to 2012 reflects in part changes in bidding strategies by brown coal generators in order to support prices with excess generation as a result of 1000 MW of wind. More aggressive bidding (towards marginal cost) would result in slightly less brown coal generation being displaced. Over both the short and long term, the result reflects constraints in the ability of power to be exported into other States through interregional transmission network. Adding more transmission capacity between Victoria and other regions could reduce the displacement of brown coal generation by wind generation (as more brown coal generation would simply be exported interstate).

1 Note that the increase in abatment from 100 MW to 1000 MW is less than ten fold, even though as wind capacity increases proportionately more generation from existing coal plant will be displaced. All else equal, the fact that more coal capacity is displaced would lead to a greater than ten fold increase in abatement. But it is likely that the higher the level of wind capacity, the lower the capacity factor of the wind capacity (as less favourable wind sites would need to be exploited). This compensates for the proportionately more displacement of coal plant. In the report, the capacity factor of wind plant falls from 37% at current capacity to 33% at 1000 MW.

APPENDIX A MARKET SIMULATION ASSUMPTIONS

A.1 Demand Forecast and Embedded Generation

The growth trend for the demand forecast adopted by MMA is based on data published by NEMMCO and applied to the 2002/03 actual half-hourly demand profiles. We have used the 2002/03 load shape as it reflects demand response to normal weather conditions. NEMMCO's forecast was originally developed by the National Institute of Economic and Industry Research (NIEIR).

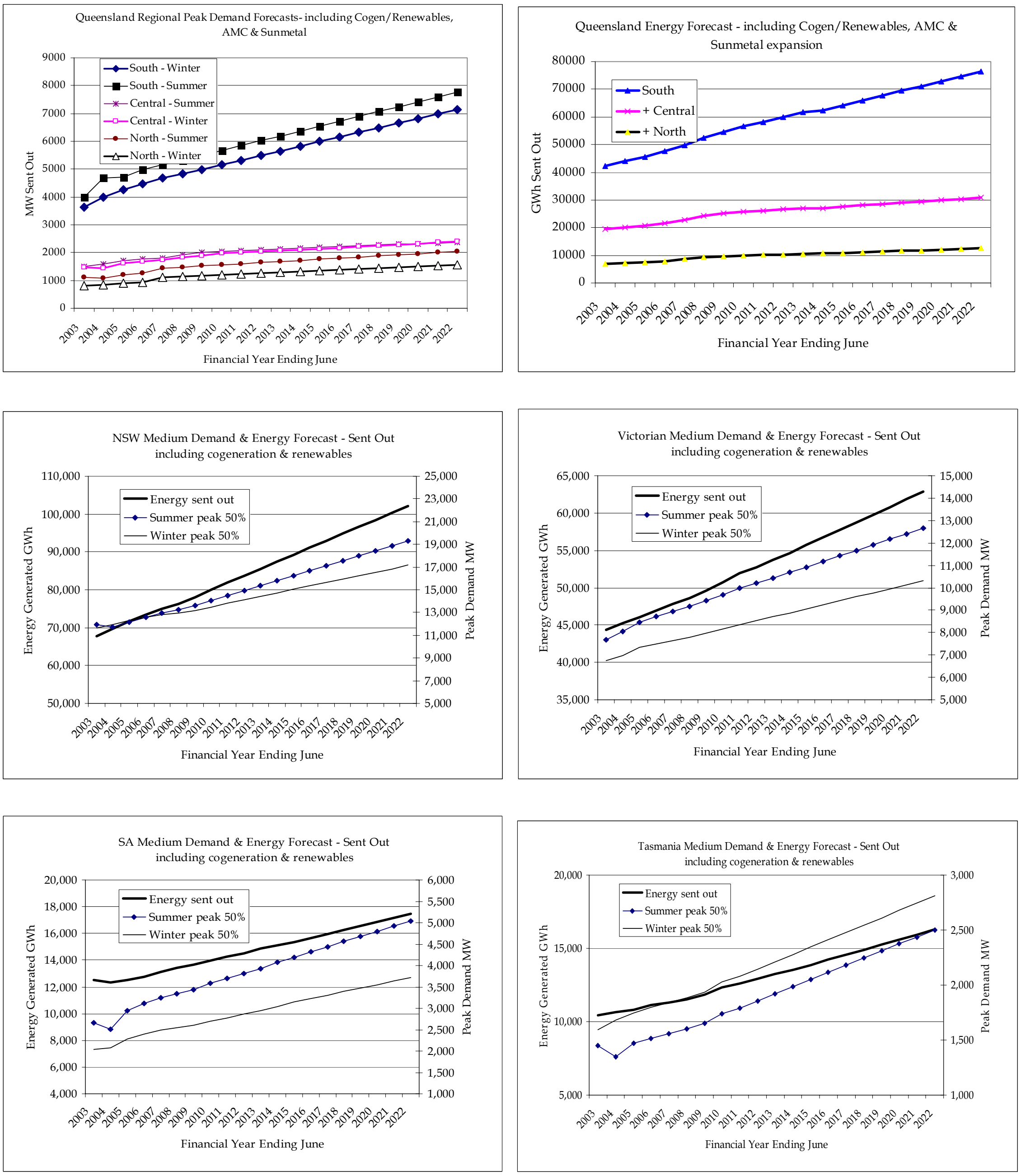
MMA further adjusted the forecasts published by NEMMCO to add back in the "buy-back" component of the embedded generation. MMA's electricity market models explicitly projects and includes this energy component for the proposed renewable energy projects. The resulting forecasts for sent-out energy and peak demand are shown in Figure A-1. The peak demands were selected with the 50% probability of exceedance (POE) in each region in each season. These forecasts are prior to any new demand side management that is expected to be stimulated by the revised NSW Greenhouse Gas Abatement Scheme.

The use of the 50% POE peak is intended to represent typical demand conditions and thereby provide an approximate basis for expected price levels and generation dispatch.

The peak is applied as an hourly load in Strategist rather than half-hourly as it occurs in the market. Because the Strategist model applies this load for one hour in a typical week it is applied for 4.3 hours per year and therefore it represents a slightly higher peak demand than the pure half-hour 50% POE. This compensates to some degree for not explicitly representing the variation up to 10% POE.

The embedded generation sent-out to grid that is forecast by NEMMCO in the SOO is added back into the forecast and MMA models the projected renewable energy developments explicitly.

Figure A-1 Medium Growth Forecasts Sent Out



A.2 Supply

A.2.1 Marginal costs

The marginal costs of thermal generators consist of the variable costs of fuel supply including fuel transport plus the variable component of operations and maintenance costs. The indicative variable costs for various thermal plants are shown in Table A-1. We also include the net present value of changes in future capital expenditure that would be driven by fuel consumption for open cut mines that are owned by the generator. This applies to coal in Victoria and South Australia.

Table A-1: Indicative Average Variable Costs for Thermal Plant ($June 2004)

Technology	Variable Cost $/MWh	Technology	Variable Cost $/MWh
Brown Coal – Victoria	$5 - $9	Brown Coal – SA	$10-$12
Gas – Victoria	$38 - $71	Black Coal – NSW	$13 - $19
Gas – SA	$20 - $170	Black Coal - Qld	$10 - $20
Oil – SA	$97-$200	Gas - Queensland	$21 - $57
Gas Peak – SA	$112-$155	Oil – Queensland	$170

A.2.2 Plant Performance and Production Costs

Thermal power plants are modelled with planned and forced outages with overall availability consistent with indications of current performance. Coal plants have available capacity factors between 86% and 95% and gas fired plants have available capacity factors between 5% and 85% depending on whether they are open cycle peaking plants or combined cycle intermediate/base load plants.

A.3 Bidding and New Entry

When MMA formulates future NEM development we assume that:

- Some 75% of base load plant capacity will be hedged in the market and bid at close to marginal cost to manage contract position. Less capacity is bid at marginal cost in NSW if necessary to support pool prices above $34/MWh. This reflects the observed exercise of market influence in NSW.
- Reserve plant at Liddell and Munmorah in NSW will return to full service when market prices permit based on stated objectives that Macquarie Generation seeks pool prices in excess of $35/MWh after return of reserve plant.
- New entrants will require that their first year cash costs are met from the pool revenue before they will invest.
- The next new entrants in Victoria will be new combined cycle plant when such plant can achieve at least 50% capacity factor. Supplementary open cycle plant will meet growth in summer peak demands.
- The next new entry in South Australia will be combined cycle plant at either Osborne or Pelican Point on the basis that the higher cost of gas justifies the additional cost of combined cycle capacity.
- Peaking capacity or demand side measures that might be purchased under the Reserve Trader role of NEMMCO to manage the risk of extreme peak demands are not included in the NEM model as these would be expected to be bid near VoLL and not

contribute to reducing energy prices under average conditions. They would have an insignificant impact on gas usage for power generation.

MMA's pool market solution indicates when prices would support new entry under typical market conditions and these are included in the market expansion accordingly. The Base Case new entry prices are shown in Figure A-2. These new entry prices include the impact of emission abatement schemes such as Gas Electricity Certificates in Queensland and Gas Abatement Certificates in NSW. Cost and financing assumptions used to develop the new entry prices are provided in Table A-2.

Figure A-2 Base Case New Entry Prices

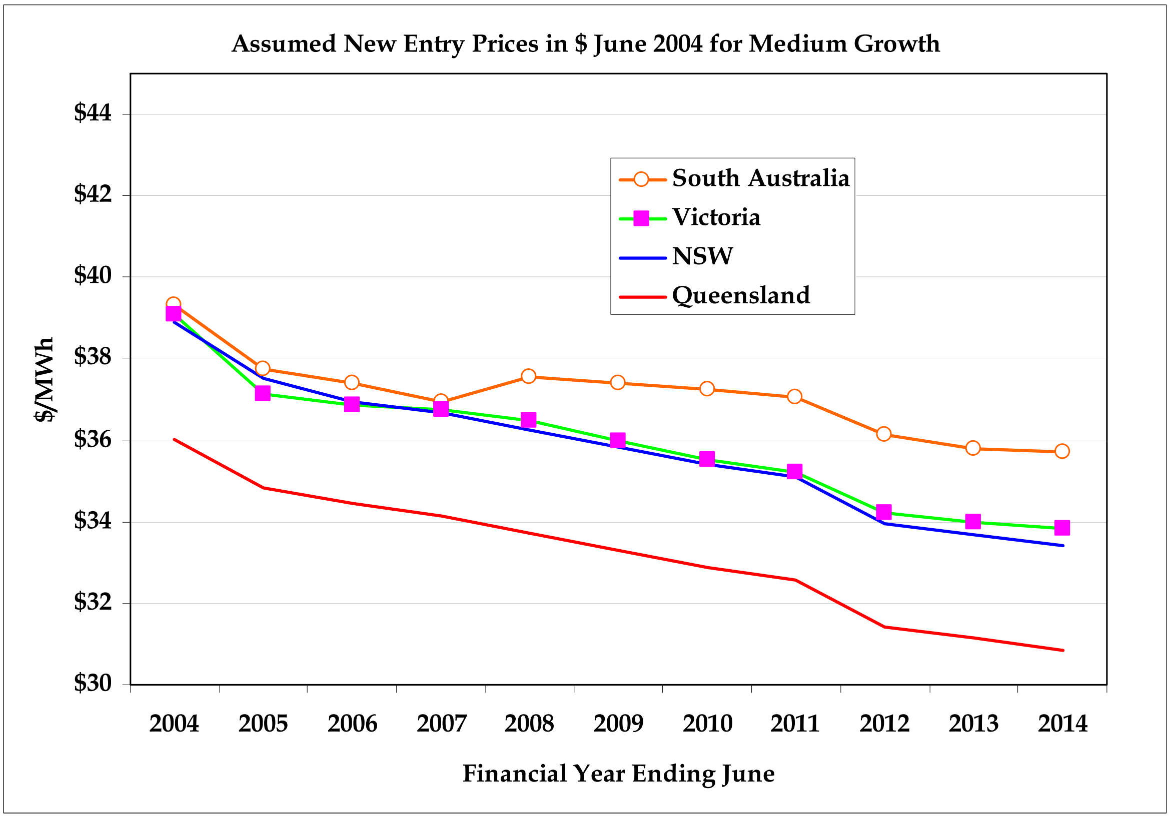


Table A-2 New Entry Cost and Financial Assumptions ($ June 2004)

	Type of Plant	Capital Cost	Capacity Factor	Fuel Cost	Cost of Capital	Interest Rate	Debt Level
		$/kW		$/GJ	% real	% real	
SA	CCGT	785	93%	3.35	8.5%	9%	75%
Vic	CCGT	789	92%	3.19	8.5%	9%	75%
NSW	Black Coal	1474	90%	1.24	8.5%	9%	75%
Qld	Black Coal	1588	90%	0.83	8.5%	9%	75%

A.4 Committed and planned entry

The recently developed power projects and mothballed plant are shown in more detail in Table A-3. The table shows the currently mothballed or reserve capacity in the NEM and the new projects which have been committed for completion within the next three years. It also shows other projects for which planning are well advanced. Torrens Island is not shown as mothballed because all units are generally available to operate. The Liddell units are also available to operate although they use operating staff from Bayswater Power Station and therefore the other two units are only operated during Bayswater unit outages.

The Kogan Creek development will commence commercial operations around September 2007. In our modelling we allow its completion to be delayed by up to 2 years to take into account any delays that often surround such developments and to avoid a price collapse in Queensland by the entry of Kogan Creek in 2007 and 2008. In Victoria, Snowy Hydro has announced the development of 320 MW of peaking capacity at Laverton North. This is expected to be commercially ready for the 2005/06 summer.

Origin Energy has also recently announced that it is seeking development approvals to build a gas-fired power station of up to 1000 MW in Western Victoria, near the township of Mortlake. It is also reported that Origin is seeking to build a similar plant in South-east Queensland. The details and timeframe for these developments are highly uncertain and accordingly we have not specifically provided for these developments in our model.

Table A-3 Mothballed Capacity and Recently Developed New Plants in the NEM

Power Plant	Generated Capacity (MW)	Region	Service Date	Status
Swanbank A	408	South Qld	Retired	Retired in June 2002. Units have been decommissioned and will be removed.
Callide A	120	Central Qld	To be Refurbished	Mothballed in April 2002. Return to service from winter 2010 according to supply/demand
Liddell	2 X 515	NSW	Reserve	Currently only 2 out of the 4 units are dispatched at one time when Bayswater is fully available, with all 4 units being operable
Munmorah	2 X 300	NSW	Reserve	Both 300 MW units are operable at short notice when other Delta Electricity units are unavailable
TOTAL Reserve	**1750**			

Power Plant	Generated Capacity (MW)	Region	Service Date	Status
Basslink	480/600	Vic/Tas	May 2006	480 MW rated capacity, 600 MW Short-term capacity
Laverton North	320	Vic	2006	Development work commenced. Construction expected to be completed by December 2005.
Kogan Creek	755	South Qld		Planning completed – awaiting market need (earliest fourth quarter 2007)
Redbank 2	132	NSW		Construction was to commence June 2003 with commissioning in June 2005. The project has been delayed due to refusal of planning approval on environmental grounds.
Braemar	3 X 150	Qld	2007	Intermediate gas fired generation. First two units available by July and August 2007 with third unit available for summer 2007/08.
Wagga Wagga	2 X 150	NSW		OCGT. Planning stages
Tallawarra	400	NSW	2008	Gas fired power station. Approved
Tomago	800	NSW		Initially OCGT with later conversion to CCGT
Total Planned	**3,487**			
TOTAL	**5,237**			**Includes reserve, new and prospective developments**

A.5 Plant Upgrading

Loy Yang Power has announced its intention to increase the capacity of Loy Yang A up to 2200MW with some units rated at 580 MW. Hazelwood Power Station was uprated from 1650 MW to 1720 MW by winter 2005 according to NEMMCO reports. Macquarie Generation has announced plans to uprate the Bayswater units to 700 MW and has canvassed the possibility of further enhancement to 750 MW eventually although at greater expense. This second round of uprating has been included from 2010 in our modelling. In addition, low-pressure turbine upgrades have been completed on all units at Liddell. The upgrades increase the Liddell capacity to 2060MW. Snowy Hydro has indicated that it intends to replace the turbine runners at Murray 2 and Tumut 3. As a result, Murray 2 plant capacity will increase from 550MW to 620MW by 2006/07 and Tumut 3 plant capacity will increase from 1500MW to 1650MW in 2008/09.

A.6 Interconnections

Assumptions on interconnect limits are based on the NEMMCO 2004 SOO and the Transmission Network Service Providers' (TNSPs) planning statements.

The SNI project was intended by TransGrid to be available by the 2004/05 summer. Following the appeal to the SNI decision by Murraylink Transmission Company in 2002, TransGrid has itself appealed the decision and meanwhile has suspended further work on the project. Accordingly, MMA has included SNI from July 2009 in the MMA model on the basis that immediate development does not provide the NEM with a least cost development as established by the National Electricity Tribunal.

In the case of the transfer limit from NSW to Queensland via QNI and Directlink, the capability depends on the Liddell to Armidale network, the demand in Northern NSW and the limit to flow into Tarong.

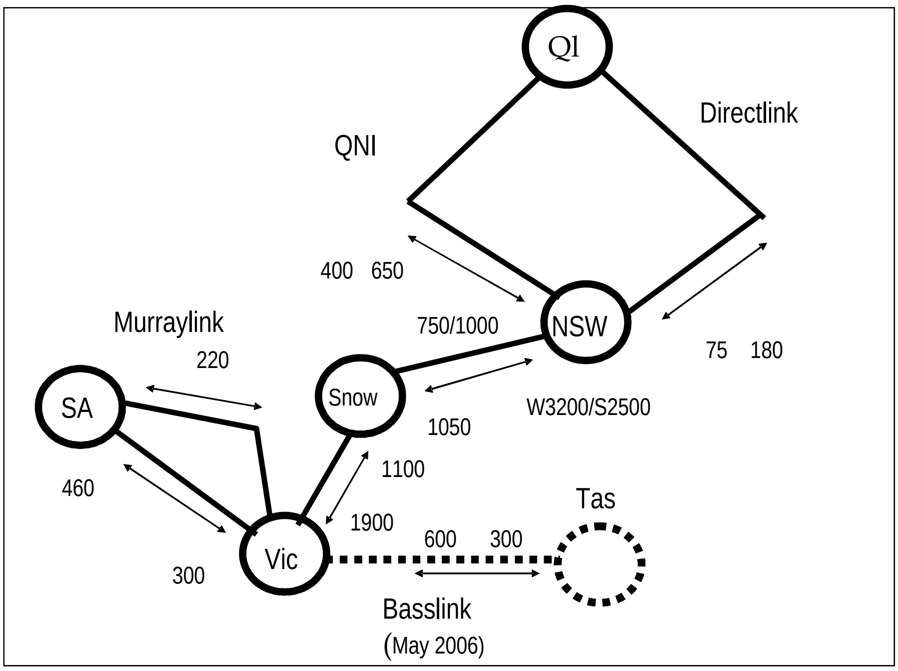
MMA has developed a seasonal model of the transmission capability assuming:

- The Northern NSW load follows the same pattern as the NSW demand less 1,039 MW allowance for base demand.
- The NSW to QNI limit is 1,300 less the Northern NSW demand estimated by this means.
- When Millmerran is operating with full generation it will back-off imports to Queensland because its cost of generation is substantially below that of NSW generators.
- Imports to Queensland from NSW via QNI to a maximum of 126 MW on average with both Millmerran units in service. An additional 180 MW is available via Directlink.
- The maximum level of import to Queensland from NSW increases to an average of 397 MW during April and 283 MW average during May when maintenance is assumed to be carried out for Millmerran, plus 180 MW from Directlink. MMA assumes that each unit at Millmerran is out for maintenance for three weeks in April and May.

The first two assumptions are consistent with the NEMMCO statement that the limit is dependent on the capability of the Liddell-Armidale transmission and would reduce by 20 MW per year due to demand growth. It also matches statements about the peak loads in Northern NSW and the impact on the NSW export limit.

The NEM transmission capacities for 2003/04 are shown in Figure A-3.

Figure A-3 NEM Transmission Capacities for 2003/04



There are a number of possible interconnection developments being considered:

- The construction of a new 200 - 250 MW interconnection between Southern NSW and South Australia, the “SNI” HVAC option.
- An HVDC link previously proposed by TransÉnergie between Victoria and South Australia which would add 65 MW of transfer capacity.
- An upgrade of the existing Victoria to South Australia export limit from 500 MW to 650 MW by additional transformation at Heywood Terminal Station (described as augmentation of the “Heywood interconnection”).
- A 400 MW or 800 MW upgrade of the Snowy to Victoria transmission link which would enable additional imports from Snowy/NSW into Victoria. The first 400 MW stage was completed by VENCorp as the regulated SnoVic facility in December 2002. This option has been further developed in the latest NSW Planning Statement to include options with augmentation of 180 MW and then up to 2500 MW total transfer from Snowy/NSW to Victoria including the allowance for the 250 MW transfer on to South Australia associated with SNI.

Basslink will have a continuous capacity of 480 MW and a short-term rating up to 600 MW. Delay to service has occurred due to the need to redesign the project to minimise the risk of excessive DC currents in the sea with the attendant risk of corrosion to gas pipelines and other facilities in Bass Strait. Commercial service is committed by National Grid Company for Hydro Tasmania and modelled by MMA by May 2006.

The further upgrades to the Heywood interconnection are unlikely to be viable for some time due to the lack of transfer constraint following service of Pelican Point and Murraylink. A further upgrade to Snowy to Melbourne is possible at some stage, especially in the event of supply shortages that cannot be addressed by new generation capacity in sufficient time. Our modelling suggests that a further upgrade of Snowy to Melbourne capacity beyond the 1,900 MW capacity would be viable by 2014/15 when Victorian and NSW/Snowy prices would otherwise separate by about $10/MWh on average.

In modelling the NEM, we do not augment the existing interconnections prior to 2009/10 on the basis that:

- Current plans for new generation will provide sufficient capacity for reliable supply and therefore high cost transmission options are unlikely to proceed early unless market participants adopt these options as the preferred way of managing high price/ demand risk.
- The practical, equitable implementation of a beneficiary-pays regime for new transmission investments is proving problematic.
- The development of new gas fired generation in North Queensland should obviate the need to augment transmission capacity to North Queensland except for local supply purposes.