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**TEL: +61 3 9699 3977 FAX: +61 3 9690 9881 ABN: 33 579 847 254**

**EMAIL: [mma@mmassociates.com.au](mailto:mma@mmassociates.com.au) WEBSITE: [www.mmassociates.com.au](http://www.mmassociates.com.au)**

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Ref: J1326 Letter 1

Ms Anthea Harris  
Project Leader  
National Emission Trading Taskforce

Email Transmission:  
To: [anthea.harris@doi.vic.gov.au](mailto:anthea.harris@doi.vic.gov.au)

Dear Anthea

**Explanation of results on electricity market impacts of emission trading**

In response to some questions regarding the electricity market modelling results, please find attached a brief note clarifying and explaining in more detail some of the results.

If you wish to discuss this note further, please contact me on 03 9674 4707

Yours sincerely

Walter Gerardi  
Director

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## EMISSION TRADING AND THE ELECTRICITY PRICES RECEIVED BY RENEWABLE AND GAS FIRED GENERATORS.

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MMA's simulation of the impact of an emission trading scheme on electricity markets indicate a high level of entry of renewable and gas-fired generation. In the business as usual scenario, we find that there is only a small amount of additional renewable generation entering the market in the period to 2030<sup>1</sup>. There was some 7,000 MW of new gas-fired generation entering the market. In the emission trading scenarios, we found about 2,400 MW of additional renewable generation entering the market, spread across all States, and about 1,000 MW of extra gas fired generation entering the market concentrated in Queensland.

Some commentators have questioned the validity of this result given the low increase in electricity price recorded as a result of emission trading. For example, it has argued been argued that a CCGT would require around \$54/MWh to enter the market<sup>2</sup>, yet the wholesale prices for electricity shown in MMA's report are lower than this.

Other commentators have argued that given the current cost of renewable generation - at a long run marginal cost of around \$70/MWh to \$80/MWh - there is no scope for additional renewable generation when wholesale prices are below this long run marginal cost with emission trading.

This note seeks to explain the model results and address the concerns raised.

### Electricity market prices

Electricity prices received by generators should in principle cover the long run marginal cost of generation. If the average electricity price received was lower than the long run marginal, then that generator makes a loss. Thus, entry of new plant is only likely to occur when the average electricity price after entry is expected to be equal to or above the long run marginal cost of generation over the life of the plant. A new plant operating at 30% capacity factor will only be selected to enter the market when the price received during the 30% of the time it operates is higher than the long run marginal cost of operating at 30% capacity factor.

MMA's simulation model of the electricity market estimates electricity prices for every hour of a typical week in each month of the study period. Because MMA's model not only selects the timing and type of new plant (gas, renewable or coal fired), it also selects the role the new plant will play in the market: base, intermediate or peak duty. The model chooses the least cost combination to the market of time of entry, type of plant and

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<sup>1</sup> Please note that we did not assume that VRET, NRET or WARET would be in place in any of the scenarios modeled.

<sup>2</sup> This is based on a long run marginal cost of \$42/MWh for a CCGT operating at 90% capacity factor and an impost to cover carbon emissions of \$12/MWh (assuming a carbon price of \$30/t CO<sub>2</sub>e and an emission intensity of 0.4 t/MWh).

role played by each new plant. The implication is that not all new plant will be base loaded and those that are not will typically receive higher prices because they are only likely to be dispatched in high price periods.

The wholesale electricity prices shown in Figure 3-7 and Table 3-4 of MMA’s report<sup>3</sup> only shown the time weighted average price, that it the average price over every hour of the year. This was used as an indicator to compare price impacts from emission trading.

However, when comparing the time-weighted average price with the long run marginal cost of generation, the prices shown are only applicable to plant that operate over most of the year (i.e. the price that would be received by a plant that operates 100% of the year). Even a base load plant, which typically operates between 90%and 95% of the year, will receive slightly higher prices than the time weighted average price. The prices received by plant operating in intermediate or peaking duty will typically receive a higher price than shown in the report. This is illustrated in the following chart, which shows time weighted average prices (as reported) as well as prices for the peak period for domestic action scenario 1. The price received in the peak period is significantly higher than the time-weighted average price.

**Figure 1: Time weighted and peak wholesale prices, NEM, \$/MWh**



Note: peak period here is defined as the hours between 7.00 am to 11.00 pm each day.

For intermittent plant such as renewable generation, the model dispatches the plant according to an assumed profile of renewable generation. Typically, a higher proportion

<sup>3</sup> MMA (2006), *Impacts of a National Emissions Trading Scheme on Australia’s Electricity Markets*, report to the National Emission Trading Taskforce, 26 July

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of wind and hydro-electric generation occurs during peak periods, and thus these generators will receive a higher price than the time weighted average prices shown in MMA's report.

Note also that the time weighted average prices for the NEM shown above and in the report are an average across all NEM states.

### **Renewable generation**

As stated above, around 2,400 MW of additional renewable generation entered the market as a result of emission trading. This ramps up from 150 MW in 2010 to 2,400 MW in 2025. This result should be put into perspective by stating that it is approximately equivalent to the additional level of new renewable generation encouraged by MRET<sup>4</sup>. Furthermore, the additional renewable generation is spread fairly evenly across all the states in Australia.

Nonetheless, a comparison of the time weighted average price shown in the report with the current long run marginal cost of renewable generation would indicate that no additional renewable generation would enter the market.

The reasons why the model selects renewable generation despite the low time weighted average price are as follows:

- As stated above, wind and hydro-electric generation receive prices higher than the time-weighted average price because more of their generation occurs in peak periods. For wind generation, on average about 60% of their generation is assumed to occur in peak periods and only 40% is assumed to occur in off-peak periods<sup>5</sup>.
- In the model, some renewable generators also receive a small benefit in the form of reduced losses because their output is used in regional areas, displacing electricity from distant thermal generators.
- MMA does not use a single estimate of the long run marginal cost of renewable generation. MMA has a data base of existing and proposed renewable generation projects which show a wide range of costs across States and across technology types. The broad assumptions for plant entering the market in 2006 are shown in Table A.18 and Figure A.3. This indicates the wide range in costs ranging from \$63/MWh to \$151/MWh for wind, mini-hydro and biomass options. The model also includes upgrades of existing hydro-electric facilities and hydrothermal geothermal options, with long run marginal costs less than or equal to \$55/MWh.

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<sup>4</sup> Also note that this capacity is about equal to the capacity of new renewable generation that will enter the market by 2020 under the Victorian Renewable Energy Target (VRET) Scheme and proposed NSW Renewable Energy Target (NRET) Scheme. These schemes were not modeled in any of the scenarios.

<sup>5</sup> There are some variations from state to state.

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- It should also be noted that the estimates of long run marginal cost are not assumed to remain static over time. The estimates indicated in the previous dot point are for plant entering the market in 2006. There is an assumption of sharp decrease in cost for some renewable generation technologies such as wind, geothermal and biomass options. Thus, new renewable plants are entering the market when the long run marginal costs have fallen significantly below the \$63/MWh to \$151/MWh estimate for 2006. By 2020, this range falls to the range of \$45/MWh to \$120/MWh.
  - In the model, entry of new renewable generation is selected based on prices received over the life of the project. Therefore, the model may select early entry of a new renewable plant even if it receives prices lower than long run marginal cost in the first few years of operation as long as prices over the life of the plant still allow the recovery of long run marginal costs<sup>6</sup>.
  - The early entry of new renewable generation is mainly some new hydrothermal geothermal plant in South Australia and upgrades of existing hydro-electric facilities in Tasmania and in New South Wales. Progressively more wind and biomass generation is installed over the period to 2025 as the capital cost falls and energy conversion efficiency improves.

### **Gas-fired generation**

As stated previously, some 7,090 MW of new gas-fired plant enter the market in the business as usual scenario between 2010 and 2030. Of this, only about 560 MW are base load plant (namely the cogeneration plant in Western Australia). The rest perform as intermediate or peaking duty plant. With emission trading an additional 730 MW of plant is added, with all of this increase occurring in Queensland (replacing the brown field expansions at Surat Basin coal plant). In addition, other plants perform at higher load duty (but not necessarily at base load duty) and there is switch to embedded cogeneration away from other types of new gas plant.

Gas plant enter the market under emission trading even though the time weighted average price is lower than the long run marginal cost with emission impost included. The reasons for this are as follows:

- There is wide range in the estimates of long run marginal cost for new plant. Note that only the long run marginal costs for new gas plant in Victoria are shown in the report. The cost of gas-fired generation in some other States such as Queensland and Western Australia follows the same trend as the Victorian plant, but are at a lower level. In other States, they are at a higher level. Also note that the cost estimates shown are for

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<sup>6</sup> This implies the plant will receive prices higher than long run marginal cost in the latter years of its operating life. For new renewable options that have an operating life beyond 2030, the model calculates long run returns and costs based on the assumptions that prices and costs in the final year of the model runs (2030) is repeated for the remaining years of life of the plant.

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an average gas-fired plant operating at base load duty. As indicated in the report, the costs for some new gas plant would be lower than this due to locational advantages. For example, the long run marginal cost of new gas plant in western Victoria and south west Queensland are assumed to have lower gas prices, with cost savings in the range of \$4/MWh to \$6/MWh less than reported for the average plant. Other plant also are assumed to receive some benefit from locating in generation poor or transmission constrained regions (such as north Queensland and south east Queensland). Embedded cogenerations (of which about 1000 MW is selected in the NEM states under emission trading) selected under an emission trading regime also receive steam benefits, which significantly reduce their long run marginal cost.

- The wholesale market prices shown in the report are time weighted average prices which would apply to gas-fired plant operating in base load duty. However, about two thirds of the plant operate at less than 80% capacity factor and receive prices higher than the time weighted average price<sup>7</sup>.
- In Queensland, some of the gas-fired generators receive revenue from GECS under the Queensland Gas Electricity Scheme, which is assumed to continue operating even under an emission trading scheme.
- The emission intensity of gas-fired generation falls over time as the energy efficiency conversion improves (from about 50% hhv basis to 65% hhv basis for a CCGT over the period to 2030)<sup>8</sup>.

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<sup>7</sup> As an indication of this, note that even under the business as usual world the time weighted average price in the NEM is lower than the long run cost of a representative gas plant. The model is choosing new coal plant for base load duty in most states of the NEM in the business as usual world.

<sup>8</sup> An improvement in efficiency occurs for all new generation technologies although at varying rates. This improvement in efficiency also reduces the emission intensity and partly responsible for the modest prices increases under emission trading.