Comments on:

***Impacts of a 20,000 GWh target for the MRET scheme*, Draft Report to MRET Review Panel by McLennan Magasanik Associates Pty Ltd**

MMA was asked to investigate the implications of increasing the MRET target progressively from 2010 onward, to reach 20,000 GWh annually by 2020. The analysis was undertaken using MMA's proprietary models and data, which had previously been used for a wider analysis of a variety of possible variations to MRET, on behalf of the AGO. I was provided on a confidential basis with printed copies of both the report for the Review Panel and the earlier report for the AGO.

The latter report contains a more complete description of both input data and the model workings and I have therefore used it to enhance understanding of the results presented in the report with which these comments are concerned.

The results of the analysis undertaken for the AGO indicate that the cost of RECs with the existing 9,500 GWh maximum scheme remains roughly constant at around $35, which is below the shortfall (penalty) charge right through to 2019, i.e. for almost the entire life of the scheme. (p. 11) (Note that the shortfall charge is not indexed for inflation, which means that it falls steadily in real terms over the life of the scheme. Under the assumptions used by MMA it falls to an effective value of $48.07 per MWh in 2010, from a starting value of $57.14 per MWh.)

However, when the target is progressively increased from 2010 onward (by about 1,000 GWh per year towards an eventual 20,000 GWh target), the report for the Review Panel shows the cost of RECs quickly rising above $35, to reach the unindexed shortfall charge at a level just under $45 in 2013. The notional cost of RECs continues to rise thereafter to a maximum of $45.60 in 2015, and remains above the unindexed shortfall charge until the end of the analysis period in 2035 (p. 22). This means that if the unindexed shortfall charge is retained, the higher target could not be achieved, as it would be less costly for liable parties to pay the shortfall charge than to buy renewable electricity. If the shortfall charge were indexed to inflation, i.e. kept constant in real terms, from 2010 onward, the cost of RECs will remain below the shortfall charge throughout the analysis period, and thus the 20,000 GWh target could be achieved. However, this comes at a significantly higher cost to liable parties, and hence to electricity consumers, of $2.03 per MWh sold over the entire study period from 2010 to 2035 compared with $1.74 per MWh if the shortfall charge is not indexed. The absolute level of costs in both cases and the difference between the two cases are higher in the earlier part of the study period (p. 26).

This result appears to be consistent with the results of the modelling undertaken in the study for the AGO, which examined the effect of increasing the 2010 target above 9,500 GWh. This shows that even a quite modest increase in the target to 14,329 GWh by 2010 will cause the price of RECs to rise above the shortfall charge before 2010. (Vol. 2, p. 62)

MMA uses a complex and sophisticated suite of models for these analyses, and a number of different factors contribute to the reported results. It appears that the most important are likely to be the two prices which, by subtraction, determine the price of RECs, i.e. the generation cost of renewable energy and the wholesale price of electricity in each of the three wholesale markets modelled, of which the NEM in by far the largest:

These factors are discussed below. Other factors affecting the results will include the following.

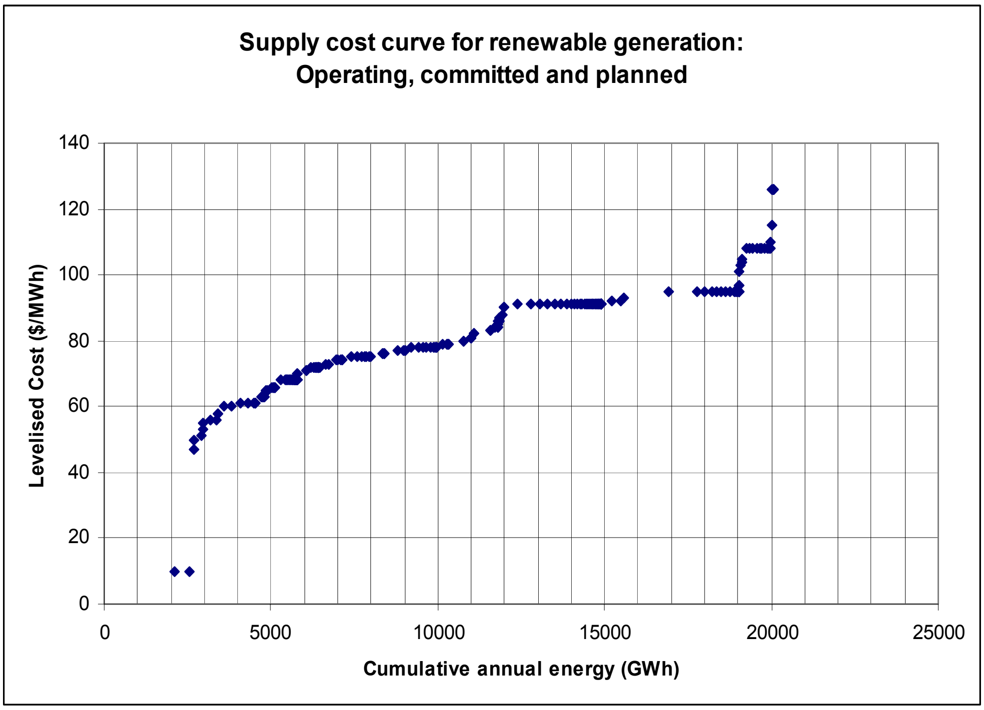
- The connection costs (transmission/distribution) faced by renewable generators: These costs are modelled as part of the cost of renewable electricity as supplied to the wholesale market, but are determined by assumptions about the location of renewable generators and could also be changed by administrative action which amended the market rules relating to cost of grid/market access for distributed generators (or new generators). However, they are a fairly small part of the total cost of renewable electricity.

- The rate of inflation: This will determine the real value of the shortfall charge, because all other costs and prices in the modelling are defined in real value terms.

The assumed cost of renewable generation is based on MMA's extensive in-house data on individual renewable energy projects, including operating, committed and planned projects, with a total capacity of 4,270 MW and annual energy supply capability of 18,500 GWh (p. 11). A full list of these projects is provided in Appendix E, Volume 3 of the report for the AGO. Supply curves of annual renewable electrical energy from new projects (excluding operating and committed projects), based on this data, are provided on p. 7 of Volume 1. The combined curve (Figure 5, p. 7) indicates that about 10,000 GWh are available at a cost of less than $80 per MWh, in addition to the approximately 2,500 GWh of operating and committed generation.

The figure below has been produced from the cost and capacity data contained in Appendix E of the AGO report. Operating and committed projects have been allocated a notional avoided cost of $10 per MWh, for illustrative purposes only, as a possible approximation to their variable costs (capital costs being sunk). It is similar to Figure 5 of Volume 1 (except for the inclusion of operating and committed projects), but with somewhat higher cost levels, presumably because the latter graph includes the effect of the assumed cost reductions for the various technologies (for wind energy 5% p.a. to 2015, thereafter 2% p.a.), whereas the data used in the graph below are costs as at 2003. Inspection of the data shows a very large number of wind projects, having total annual energy supply capacity of nearly 3,000 GWh, all with a levelised cost of $91/MWh. Hydro, wind and MSW projects with total annual supply capacity of 4,100 GWh have levelised costs between $91 and $95 per MWh. It is presumably these projects which supply the great bulk of the additional energy required to achieve a 20,000 GWh target.

The results of the modelling are highly sensitive to the assumed costs of these projects. Figure 3.1 (p. 22) of the report for the Review Panel indicates that the cost of RECs with the 20,000 GWh target is never more than $10 above the unindexed shortfall charge. Thus if assumed costs were lower by roughly this amount, it is probable that the augmented target could be achieved within the unindexed shortfall charge limit.



Sensitivity analysis case 4 tested one of the key assumptions about the cost of renewable generation by reducing the WACC assumed to be required for renewable projects and assuming more rapid reductions in the real capital costs of all technologies. These changes had a very large effect in the last few years of the study period (from 2030). Again the relative cost of renewable generation and hence REC prices were reduced, because renewable generation is more capital intensive than non-renewable, and hence more sensitive to changes in capital cost parameters. The very large change in the last few years may result from the lower cost of the large block of wind, hydro and MSW projects having present levelised costs at or just above $91/MWh, referred to above. There is insufficient information provided to deduce how much these assumptions change the levelised costs of wind and other renewable technologies, relative to the base case.

Regarding the wholesale price of electricity, the AGO study reports that, with the current MRET target, the Australian average wholesale electricity price will remain in the range of about $38-42 per MWh from now until 2020. (Volume 1, p. 11) This price is determined by a number of factors (Volume 2, p. 35), but the cost of non-renewable generation will predominate. In particular, "new entry costs are assumed to provide a cap on future market prices" (Appendix B, volume 3, p. 14). New entry costs are based on the assumption that new market entrants will adopt a pre-emptive entry strategy by setting prices which are $1-$3 per MWh below levelised project costs (p. 15). The resultant new entry costs are shown in Table B.2. These appear to be more than $3 below quite widely accepted views as to the long run marginal cost of new coal fired generation (in Queensland and NSW) or new CCGT generation (in Victoria and SA).

It is unclear what assumptions have been made about the new entry cost of generation over the longer period (2015 to 2035) that is relevant for the MRET Review study, other than the assumption that real fuel (coal and natural gas) prices will decline by 0.61% per year (escalation at 75% of the assumed 2.5% p.a. inflation rate – p.17). This seems an implausible assumption over such a long time scale, particularly for gas. It is also unclear whether market prices set by continual deployment of pre-emptive pricing strategies by new entrants will in fact continue to attract sufficient new entrants to replace decommissioned plant and meet demand. If market prices were higher than modelled, the price of RECs would be lower, all else being equal.

The effect of the assumptions about the cost of fossil fuel generation were tested by sensitivity analysis cases 1 and 2, which specifically increase fuel costs and capital costs respectively by 20% above the base case. In both cases the cost of RECS is reduced, though it still remains above the unindexed shortfall charge level for most of the study period. This result means that the overall cost to consumers of compliance with the increased target would be less. In addition, there would be some further increase in renewable generation, even with the shortfall charge unindexed (p. 35). The locational and/or timing advantages of some renewable generators would further reduce the average competitive disadvantage of renewable generation relative to fossil fuels plant (p. 39).

It is worth noting that a 20% increase in fuel costs over 10 years from 2005 to 2015 is equivalent to and annual increase of 1.8% p.a., which compares with the base case assumption of a decline of 0.61% p.a. The latter equates to approximately 6% over 10 years and 12% over 20 years. These are in fact relatively small changes compared with the dramatic falls in unit fuel costs experienced in earlier periods, e.g. mid 1980s to mid 1990s when they roughly halved, according to ESAA statistics.

A final sensitivity analysis case combines the other cases, i.e. includes both higher fossil fuel generation costs and lower renewable generation costs. In this case, REC prices are estimated to be constrained by the unindexed shortfall from 2021 to 2030, but the difference between the two is never more than $3 (p. 36).

To summarise, the gap between the cost of RECs and the unindexed shortfall charge, and thus the assessment of whether the shortfall charge will need to be indexed, is determined as the difference between two larger numbers, each of which are several times larger than the difference between them. The simple mathematics of such a relationship always means that the difference is highly sensitive to relatively small changes in either of the two larger numbers. This is illustrated by the results of the sensitivity analyses.

As the MMA report observes, caution should be exercised before concluding that the apparent need for indexation of the shortfall charge to achieve the higher target casts doubt on the long term sustainability of a commercial renewable generation industry (p. 37). Even in the base case, indexation is only required for the period up to about 2020 for the target to be achieved over the next 15 years (p. 41). The report suggests that partial indexation may be effective in achieving the target. (Note, that if the market for RECs is perfectly competitive this would not affect the overall average REC price, compared with the fully indexed case, though there may be some symbolic value in partial indexation.) Conceivably, another alternative would be to index the shortfall charge but reduce the period over which accredited generators are able to earn RECs. This implies regarding RECs as a form of assistance that is particularly helpful in overcoming difficulties associated with the high up-front (capital) costs of renewable generation.

Overall, given the level of uncertainty about many of the parameters, I would be unwilling to make a firm conclusion that an increased MRET target after 2010 can only be achieved by indexing the shortfall charge. I am aware that this conclusion begs the question of what level of certainty about the future shortfall charge value will be needed to provide the degree of certainty sought by renewable energy project developers and investors.

This observation in no way implies that either the renewable energy costs or the market prices modelled by MMA are considered to be wrong or inappropriate. It simply serves to suggest that the results may be very sensitive to these particular values, and thus to the assumptions which lie behind them. The sensitivity analyses illustrate the extent of this sensitivity and the report itself advises caution about drawing firm conclusions from the base case results.

Hugh Saddler
Energy Strategies Pty Ltd
22 September 2003