Critical Comments on

## Zero Carbon Australia,

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Energy Institute, (2011 version).

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10.5.2014 revision.

The ZCA report claims to show that Australia could run entirely on renewable energy by 2020. This document is the second revision of the critique I circulated in 2010, in the light of more recent information

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The lengthy and detailed ZCA report is a valuable contribution to the energy discussion, containing much up to date information and many ideas and proposals that are promising. However I think there are a number of points where examination of data and assumptions shows that the report is quite mistaken in its conclusion that Australia can convert to full dependence on renewables.

### The supply target.

The spectacular conclusions ZCA arrives at are largely due to the energy supply target set, which is very low. The 2010 Australian final or end-use energy consumption is stated as 3,900PJ/y, and ZCA says this can be reduced to 1,660 and kept there. (However Fig 4.1 represents the task as supplying an average of 1,317 PJ or 35 GW, and the wind and solar thermal plant requirements stated seem to correspond to this lower figure.)

The recent fall in power demand means that probable future demand is now quite uncertain but the ZCA target seems to me to be much lower than the likely level. Factors causing the fall include the decline of manufacturing, the GFC downturn, the closure of an aluminium smelter, rising electricity prices and the rapid rise in household PV systems. The last factor does not represent a fall in demand. Australian energy consumption had been growing at over 2% p.a. until the mid 2000s, and ZCA notes electricity consumption was growing at 3.15% p.a., and transport energy use at a similar rate. Population is expected by the ABS to rise by up to 75% by 2035 and it is very unlikely that such a number will generate a demand lower than the present population. If the 2035 population were to have present Australian per capita power consumption demand would be more than four times the ZCA target. Conservation and efficiency effort I not likely to cut that by 75%.

ZCA provide almost no case for their very low target figure, apart from discussing (little more than mentioning) various conservation possibilities. They state their assumption that the general efficiency of energy use can be reduced by 20%. They also make vague statements such as "Ongoing per capita efficiency gains of 1 – 1.3% p.a. after 2020 keep total demand steady at least to 2040, while allowing for population growth." (p. 15.) No support is given for this statement. On p.130 they say their plan "…intends to decouple energy use from GDP growth", with no further comment. No reasons are given for thinking that decoupling is possible. There is much historical trend evidence that energy growth is tightly tied to economic growth, and it now seems to be well established that "de-materialisation" of the economy is not occurring. Again the ZCA assumptions are huge, i.e., that the pre-GFC factors recently driving over 3% p.a. growth in both electricity and transport energy demand will cease to operate from now on or that future demand can be cut to and held at one-third of 2010 demand … while population increases by possibly 75% by 2035.

The ZCA claim depends significantly on assumed conservation and efficiency achievements. They discuss substantial possible reductions being discussed in building energy use (via heat pumps and insulation) and in transport (via electric vehicles). However it is not clear how big these can be, and CZA has assumed extreme achievements. Some recent reports contradict the common assumption that large scale reductions in these two areas are likely, mainly because previously the substantial embodied energy and other costs involved in saving energy have been overlooked. Crawford and Stephan, (2013) find that an all-inclusive embodied energy study of the much-acclaimed German Passivhaus shows that it actually uses more energy in its lifetime than a normal German house, due to the large amount that goes into its production. The Victorian Electric Vehicle study found much the same effect with electric vehicles, again due to energy embodied in inputs to construction.

## To what extent can the economy be run on electricity?

The ZCA strategy assumes almost all energy can be provided in the form of electricity. Although it seems possible and wise to move in this direction it is far from clear what the limits are. The first general limit is to do with functions that could practically be converted to electricity, and the second is to do with the increased scale of the intermittency problem.

## Embodied energy costs.

The report's figures for the energy needed to build wind and solar thermal plant are highly challengeable. The embodied energy costs of renewables is a very important but unsettled issue with major implications for their viability. Yet until recently it has been a neglected topic and the evidence has been scarce and unsatisfactory. The most important issue is whether a full accounting of all ”upstream” and “downstream” factors has been included. For instance in addition to the energy it takes to produce the aluminium for PV modules it is important to include the appropriate fraction of the energy it took to produce the aluminium smelter, etc. It is also important to include the “downstream” factors such as the losses and costs involved in replacing inverters, dust on modules, aging of cells, and poor maintenance. These and several other factors detract significantly from energy provided to the user and thus from the ER numerator, while adding to the denominator.

For PV panels Lenzen et al. (2006) conclude that a full accounting of upstream factors actually trebles the commonly stated pay-back time, making it equal to one-third of plant lifetime. The figure Lenzen et al., (2006) give for PV is more than 6 times the figure ZCA states. Palmer (2013), Weisbach et al., 2013), Crawford et al., (2006), and Prieto and Hall, (2013) have recently published surprising conclusions on the ER of PV when all upstream and downstream factors have been taken into account. These are between 2.4 and 4. Crawford has said his studies and those of Lenzen et al. seem to be the only ones at that time which deal with all upstream factors for PV. (Personal communication.)

ER figures depend greatly on what is included in calculations, magnitudes assumed, and especially the radiation at the site in question. (Palmer analyses Melbourne, Hall and Pietro Spain.). The issue is probably far from settled but these extremely low ERs suggest that when thorough analyses for wind and solar thermal have been carried out ZCA’s assumptions will be seen to be far too optimistic.

ZCA’s Fig. 2.27 on p. 36 seems to put the wind figure at 1% and solar thermal at 2%. (No sources are quoted.) Lenzen et al. state 6.6% for wind, taking in upstream factors, almost 7 times the figure given by ZCA.

I have found the literature to be especially scant and inconclusive regarding solar thermal systems. Lenzen reports 10.7% for central receivers but this is from some time ago and none of the about eight studies I have found (e.g., as listed by Dale, 2013, who states a questionable 20%) explain assumptions adequately or appear to take in any upstream or downstream factors. It does not seem that there has been any attempt to give a full accounting for solar thermal plant. ZCA provides no support, documentation or reference for the low figure they assume.

No proposal involving significant reliance on renewable energy is of much value unless it includes a detailed itemized list of upstream, direct and downstream energy costs and losses and a derivation from these of a net output value, and then an embodied energy cost, all open to examination and assessment by the reader.

## Wind.

ZCA assumes that wind will provide 40% of energy needed. However Lenzen's review (2009, p.19) and several others seem to agree that in general problems of integration limit wind to a 20% contribution to electricity supply, possibly 25%. This general figure can be exceeded but at increasing cost; see below.

There is extensive documentation on the magnitude of the intermittency problem. ZCA does not deal with the big gap problem nor with the probability that a big wind gap will coincide with a big solar gap. This is common in Europe; i.e., the occurrence of several consecutive days of continent–wide cold, calm and stable weather. Several studies have documented this, including Oswald, Raine and Ashraf-Bull, 2008, Coelingh, 1999, and Sharman, 2005. Lawson, 2011, and Davey and Coppin, 2003 document the problem in Australia. Elliston, et al. (undated) reproduce the NEM total wind output for 2010, sowing negligible generation between 17th and 20th May, and zero output at least once. They say low energy events are more likely in winter in the south of the continent, and last 4 to 8 days. Recently Zhang et al. (2012) report the alarming finding that climate change seems to be bringing long anti-cyclonic periods to Central Asia and Western Europe, periods of several continuous days of stable calm, cloud and cold.

ZCA argue from the Danish situation, where the target for wind's contribution is 40+%, but this is not a satisfactory argument, indeed it is almost irrelevant as it is well known that Denmark's situation is unusual. It is a very small nation close to large nations and therefore able to export surpluses and import electricity when the winds are down, to draw on the regions considerable hydro power when necessary, and to use surplus wind energy to supply district heating. None of these conditions applies in Australia.

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More than 20-25% of demand can be met by wind, but with increasing difficulty and cost. The recent CSIRO study (Sayeef, 201), the OECD study, and that by Miskelly (2014) detail the magnitude of the problem. Because wind input varies so greatly equipment is needed to deal with grid destabilization, surpluses and shortfalls. Miskelly reviews the combined Australian wind sector and documents more or less continuous fluctuation between high and low input. He discusses one recent year when total Australian wind farm input fell to negligible 156 times, for a total of 6.5 days.

It is generally assumed that adding widely distributed farms reduces intermittency of aggregate supply but when Miskelly compared the situation before and after the installation of much capacity he found that this did not "smooth" aggregate input. These findings mean that the entire wind capacity has to be backed up by fossil fuelled generation capacity, and none of the previously existing fossil fuelled capacity can be retired. As Palmer points out the German PV sector has added some 30% to power generating capacity without adding to power consumed, so this is added capacity that can be substituted for fossil fuelled capacity from time to time, but it is not capacity that adds to power provision. Even more problematic are the implications of the associated ramp rate problem. Miskelly documents the frequent precipitous rises and falls in total output. He says this means that for a large scale wind sector the back up can't be the existing coal-fired plant but would have to be newly built gas-fired plan

In addition surpluses have to be dumped or exported. South Australia is near the limit for wind input unless interconnectors to Victoria are built, and Miskelly says the two under consideration will cost $4 to $10 billion. South Australian average wind output is around 0.6 GW, but the cost of these interconnectors could pay for 3 GW of coal-fired generating capacity.

### <u>Capital cost to deliver a kW in winter.</u>

In my view the most appropriate measure with which to assess the capital costs of the components of a renewable energy system, and of the whole system is the cost of sufficient plant to deliver 1 kW, in the conditions that apply. In this case those conditions include winter radiation and wind levels, supply at distance for solar thermal, remote area construction for solar thermal, the effect of low DNI on solar thermal performance, and embodied energy costs.

AETA estimates the <u>present</u> capital cost of on-shore wind at $2,250/kW(p). Most estimates of the cost of on-shore wind do not expected it to fall much in future, but ZCA expects an almost 50% fall in the decade to 2020. (Table 3.14, p. 67.) The Australian total wind system has recorded a capacity factor of 24% for a recent winter month, so the cost of sufficient turbines to deliver 1 kW then would be $9,375. ZCA proposes sufficient generating capacity to meet a 37 GW demand, and wind is to provide 40% of that capacity, i.e., 14.8 GW. At $9,375/kW delivered the capital cost would be $139 billion, which is just about twice the $72 billion sum ZCA states.

## <u>Solar Thermal</u>

### <u>Output issues</u>

The proposal involves 156 central receivers each of 220 MW capacity and 2.6 million square metres of collection field area, costing $739 million each, for a total of $172 billion dollars. These have a total peak capacity of 42.5 GW and are expected to provide (as distinct from produce, because much surplus is to be dumped) 195 TWh/y, which corresponds to a continuous flow of 22.3 GW. The following argument is that the claimed number and the cost are much too low.

<u>The significance of low Direct Normal Irradiation (DNI).</u>

Analyses and predictions of solar thermal plant performance typically use one constant value for efficiency, i.e., the value for peak conditions. The near term future value is commonly expected to be 17 - 19%. What is commonly overlooked is that most of the time solar thermal devices will have to operate in levels of DNI that are well below peak levels, meaning that their efficiency will be significantly lower. (Weisbach et al., 2013 note this effect but do not discuss it.)

Trainer (2013) considers the (scarce) evidence on the relationship between output and DNI level for central receivers. (There is good evidence for dish-Stirling systems.) For instance, the Blythe Riverside 100 MW central receiver (theoretical, not actually operating) example given by NREL's SAM shows that the average monthly radiation level at that site in winter is about 40% of the average summer value, but output is 57% lower. This corresponds to a reduction in efficiency of 24%, comparing mid-winter generation with mid-summer generation. The main factor causing the reductions is likely to be the parasitic energy loss, including the power needed to move heliostats and to pump heat to tanks. This loss is more or less constant across all levels of radiation so when DNI is low it is subtracted from a lower output value. NREL estimates the parasitic load at around 10% of (presumably) peak gross power output.

The gap between peak efficiency (as distinct from summer) and winter efficiency is greater still. Peak efficiency is 17% but the winter monthly output from this example plant of 20.5 million MWh corresponds to a solar-electricity efficiency of 13% (…for DNI averaging 5.2 kWh/m$^2$/day.) This evidence does not enable confident conclusions but it seems plausible that if a central receiver's efficiency at peak radiation is 17%, then at 600 W/m$^{2,}$ or when DNI is roughly 6 kWh/m$^2$/d, it would be in the vicinity of half that value. There is evidence that the deterioration accelerates, especially for troughs. (Odeh, Behmia and Morrison, 2003.) It is therefore possible that when average monthly DNI is say 4.5 kWh/m$^2$/day, meaning it averages about 600 W/m$^2$ for 7 hours a day, a third of the radiation is so far below this value that it generates at negligible efficiency.

Thus it is quite misleading to apply a uniform efficiency figure that applies to peak conditions to the daily total DNI received, because especially in winter a far lower value would apply, and much of the winter DNI received might have been at a level at which negligible generation would take place.

The effect of low DNI might be surprisingly large. Guilen (2008) reports that solar thermal plants located in regions where DNI is down 24% compared with ideal levels and sites produce electricity that costs 4 times as much.

The ZCA proposal does not take this factor into account. It intends to locate three of the 12 farms in situations similar to Mildura, where it states winter DNI averages 4.8 kWh/m$^2$/d. (However the NASA climate data source indicates that the long term average for Mildura in winter DNI is only 3.9 kWh/m$^2$/d and that in some years it can average 3.45 $kWh/m^2/d$. (Bureau of Meteorology data show that in winter Mildura has more than 11 days a month “cloudy” and only about 7 days a month “clear”.) The other two of these three sites have only slightly higher DNI levels. The foregoing evidence on the reduction in generation efficiency with reduced DNI suggests that much of the time in winter little power would be generated by plants at these sites. ZCA proceeds as if they would operate with the same plant efficiency regardless of DNI.

The significance of the issue is evident when ZCA’s average output figures are examined. The average DNI for the 13 sites is given as 7.9 $kWh/m^2/d$. This would indeed produce the stated annual 195 TWh/y target, at an average plant output of 174 MW, but only if efficiency was 17%. But 17% is the assumed plant efficiency given peak conditions, i.e., radiation of c. 1000 $W/m^2$. If the daily total is 7.9$kWh/m^2/d$ the average DNI would be about 800 $W/m^2$, 20% below the level that would enable 17% efficiency. The analysis in Trainer 2013 indicates that in winter the efficiency of a plant located at Mildura would average under 50% of efficiency under peak conditions. If so radiation of 4.8 $kWh/m^2/d$ and generation efficiency of 8.5% would produce only 0.4 $kWh/m^2/d$, and a plant with 2.6 million $m^2$ of collection field would produce 1.04 million kWh/day, corresponding to a 24 hour continuous rate of 43 MW…a long way from 174 MW.

Thus the issue of efficiency at low levels of DNI indicates that far more central receivers would be needed than ZCA assumes. Two more considerations further increase the number. A realistic assumption for embodied energy costs might be in the region of 5 times that assumed by ZCA, further reducing net output from the system and increasing perhaps by 10% the number of central receivers needed. Secondly ZCA propose locating about half their plant thousands of km from most demand and the energy loss in transmission from distant sites might be 10 – 15% of output, and the embodied energy cost of the lines should be accounted to the solar thermal sector. .

These factors might conceivably multiply the number of solar thermal units required to meet the ZCA output target by 1.5.

## Solar thermal capital costs.

ZCA say the (future) cost of one central receiver would be $739 million, or $3,360/kW. This seems to be at the lowest end of the range evident among published estimates. Most of the (relatively few) estimates for future cost I have found are around $4,500/kW.

Very few central receivers have been built so we don’t know whether real world costs will be close to the estimates. Here’s a sobering number…the cost for the recently completed Spanish Gemasolar 20 MW plant has been reported at $(A)548 million, which is $27,400 kW. (Solar Australia, 2011.) The plant is claimed to send out 110 million kWh/y, so the capital cost per kWh sent (as distinct from peak) would be around $41,000, whereas for coal-fired capacity it would be $3,100 (…according to AETA.)

Gemasolar is the first of its kind, with 15 hour storage, so the cost would have been higher than it will settle to eventually, but its cost per kW of capacity is more than 8 times the cost ZCA assumes. The published estimates expect only a 33% reduction in the present cost of solar thermal plant in Australia, and AETA expects only a 25% fall in the Gemasolar cost.

Note that despite its 15 hour storage Gemasolar cannot provide 24 hour supply. Its capacity factor is reported at 63%. The NREL plot of its annual output shows output seems to be totally from gas a lot of time, (limited by Spanish law to 15% of total output.) Central receiver operators will not release output data so we have no idea how well or poorly they perform, especially in winter.

Following is an approach to the estimation of capital cost. ZCAS says an average 22 GW is to be delivered by the solar thermal sector. Let us assume that it is to make this contribution in winter. In a winter month the example central receiver given by NREL (2011) in the SAM package delivers the equivalent of about a constant 20 MW net flow (assuming 5.2 kWh/m$^2$/d average winter DNI for the site, 8% <u>higher</u> than for Mildura, a ZCA site) and costs $658 million. ZCA would need 1,100 of them, and the cost would therefore be $734 billion. Making the common assumption of a future cost reduction of one-third, this reduces to $489 billion. Yet ZCA says their 156 units will cost only $172 billion.

However this derivation is much too low because it does not take in some important factors, the main one being the fact that ZCA assume 17 hour storage. The above derivation is based on the NREL example which is for 6 hour operation from storage. Before this can be taken into account a confusion over the term Solar Multiple needs to be dealt with.

## <u>The solar multiple issue.</u>

ZCA refer to their proposed plant as being able to operate for 17 hours from storage and therefore as having a Solar Multiple of 2.7. This seems to be a mistake (which is also made by Elliston, Diesendorf and MacGill, 2013.) The common and meaningful sense of the term is that a solar multiple of 1 means that the ratio of the energy collected by the field area to the generating power of the turbine is 1, so that it can use all energy collected without storing any. If there is enough storage to run the same turbine at full capacity for 6 hours after the sun has gone down the field must be twice as big as for the no storage case, meaning that the SM is 2. For 12 hour storage the solar multiple is 3 and for 17 hours it would be 3.67.

This is clearly the usage in several discussions, such as by Lovegrove et al., (2012), James and Hayward (2012, p. 12), and Trieb, et al. (2009) who state, that 18 hours storage means the SM is 4. The IRENA review of solar thermal power (2012) makes what seems to be the correct use at a number of points, e.g., pp. 8, 14, 18 and 30. The US DOE (2012) more or less corresponds, saying that for 11 hour storage the SM would be 2.5; i.e., a little larger than the above references would suggest. In Elliston, Diesendorf and MacGill, 2013, p. 8, the apparently correct figure is quoted from AETA: "The AETA provides cost data for CST plants with six hours of thermal storage and a solar multiple of 2."

AETA (2012 p.37) gives cost estimates for central receivers without storage and with 6 hour storage, but unfortunately not for longer periods. They say that adding field and storage to enable 6 hour operation from storage increases plant cost from $5,900/kW(p) to $8,308/kW(p), i.e., by 41%. For a plant with 17 hour storage this amount of field and storage would have to be added to the cost of a plant with 6 hour storage another 1.67 times. Thus the total cost would be 1.67 x 41% = 68.5% higher than the cost of the plant with 6 hour storage, a multiple of 1.68.

Lovegrove et al., (2012) give figures for LCOE which seems to imply a higher multiple. They indicate that 15 hour storage would involve raise the LCOE to 1.8 times that for 6 hour storage. Trieb (2010) indicates a similar figure.

Therefore it seems that the present cost per kW of peak capacity capable of operating for 17 hours from storage would be 1.68 times the NREL SAM example cost of $6,580/kW(p).

### **Net winter output and cost .**

The following derivation of the all-in cost of sufficient plant to deliver 1kW in winter, at distance, net of embodied, transmission and remote area construction costs is so high as to be unbelievable at first sight. Yet all assumptions and steps in the derivation are clearly stated enabling others to check them, or to make different assumptions and draw their own alternative conclusions. I am not highly confident about this derivation, but I cannot see where it is seriously mistaken.

The NREL SAM example plant used here has 100 MW(p) capacity, but produces only 20 million MWh in winter, corresponding to a 24 hour flow of 28 MW (at a site receiving 5.2 kWh/m$^2$/day, around that which ZCA says applies to its sites.) The cost of the plant is $658 million and if it sends out 28 MW the capital cost per kW sent out in winter would be $23,500.

Four factors increase this cost by a factor of 2.6.

If17 hour storage is assumed the discussion of solar multiples above indicates that this cost must be multiplied by 1.68, bringing it to $39,245/kW sent out.

To this sum must be added the effect of an embodied energy cost. If this is 10% the above capital cost rises to around $43,600/kW(p).

To this must be added the effect of the energy loss in of long distance transmission. If this is 10% the capital cost rises to $48,450/kW.

Finally there is the effect on cost of construction in remote areas, which would be the norm for solar thermal power as it is best located in deserts, and about half the ZCA sites are thousands of km from settled areas. According to Lovegrove et al. (2012) this might multiply total costs by a factor of 1.3+, to the region of $63,000/kW.

The total capital cost for sufficient plant to produce 42.5 GW in winter would therefore be in the vicinity of $2,680 billion…around 15 times the ZCA claim.

Again this derivation is crude and could be significantly mistaken, but it would seem that major errors would have to be shown before it would be possible to reject the implication that the ZCA total capital cost for the solar thermal sector is far too low.

### **Another approach.**

Here is another way of attempting to assess the plausibility of the ZCA analysis.

Fig. 4.2 shows that the 43 GW of solar thermal capacity assumed is being claimed to produce about 800 GWh on a winter day, which corresponds to a flow of 33 GW. But as there are 156 solar thermal units, each would have to be delivering 213 MW…which is their rated output in peak conditions.

Now let us see what the 156 units might be delivering when the above four reduction factors, and winter radiation are taken into account. In winter the NREL example unit produces at 28% of peak capacity, so the 220 MW unit ZCA assume would generate c. 61.6 MW. Applying the above four reduction factors would bring this down to 24 MW….around 10% of the ZCA assumption.

Again the conclusion is so different to the ZCA conclusion that one suspects the derivation, but the possibility that the ZCA analysis is far too optimistic is at least apparent.

### **The intermittency problem for solar thermal.**

The crucial problem for renewables is how much additional plant would be needed to keep up supply through periods when there is little sun and wind.

Proposals for 100% renewable supply rightly point out that technologies would be combined or “bundled” to maximize the extent to which some can make up for shortfalls in others when they occur. So on a poor solar day in Mildura, or at all solar thermal sites the aim is to make up the shortfall by drawing on good winds. ZCA is claiming that this can be done with little need to resort to biomass and hydro back up, as illustrated in Figs 4.2 and 4.3. This is being claimed despite the fact that the solar thermal storage capacity assumed is only capable of generating over night (not even that if the Gemasolar 63% capacity factor applies). In other words the solar thermal storage assumed cannot macke any contribution to getting through one cloudy day, let alone a run of them.
The problem here is to do with how representative the two years in Figs 4.2 and 4.3 are. They seem to be years in which there were almost no periods in which solar radiation was negligible for a day or so, let alone for several days in a row.

Fig 4.2 represents the wind and solar thermal input for the whole of 2009 and it appears that solar radiation is represented as being more or less the same 800 GWh every day of the year. (The plot for 2008 shows more variation.) This is somewhat difficult to accept, although the AEMO data do reveal 2009 to have been a good year for solar radiation (as distinct from 2010, see below.) Elliston (below) comments on the frequent occurrence of periods of several days in a row with low radiation at many ideal Australian sites.

As part of their study of Australia’s renewable energy potential AEMO has recently made available hourly DNI data for 42 regions covering the eastern 1/3 – 1/2 of Australia. I have attempted to analyse these figures with special interest in the periods in which there is little or no radiation, and in the variation in DNI levels. (Trainer, 2013.) Both issues seem to have been entirely neglected in the renewable energy field, and to have seriously negative implications for solar thermal and PV power.

I took six good and distributed sites from central Australia to Mildura and found that in the 92 day period at the end of 2010 there were 12 (non-overlapping) periods each lasting 4 days or more, including 48 days in all, in which DNI averaged across the sites did not reach 500 W/$m^2$ at any time during the day. Reference to power curves (mostly available for dish-Stirling systems but also somewhat evident for central receivers…and apparently far worse for troughs) indicates that <u>almost no power</u> would have been generated on these days.

<u>Use the heat storage capacity of solar thermal?</u>

ZCA do not explore more than 17 hour storage but some suggest that the intermittency problem could be overcome by equipping solar thermal farms with much longer storage. This might sound like a plausible storage strategy but it would be quite problematic in view of the amount of heat that would have to be stored to make much difference.

If electricity from a 1000 MW(e) solar thermal plant was to be dispatched from stored heat for 4 cloudy days, some 280,000 MWh of heat would have to be stored and storage capacity would have to be around 14 times that presently being built into solar thermal systems. Provision to store for 4 days would require about 5.6 times as much storage capacity as ZCA assume. Note also that a 4 day task would involve a significant heat storage loss. At present it is a negligible 1%, but that is for c. 6 hour storage. This indicates (debatably…giant tanks, less surface area) that for 96 hour storage it would be c. 16%, and this would be continual as very big tanks would need to be kept full all the time.

## Dependence on biomass.

ZCA say that the few gaps could be plugged fairly easily by use of biomass, making up about 15% of electricity produced. This is misleading as it might be taken to mean that the biomass capacity to be built would only need to be 15% of the total 37 GW capacity. But if biomass is to plug the gap when there is little or no sun or wind across the eastern half of Australia we would need enough of it to meet almost all demand, i.e., 32 GW of biomass generating capacity (i.e., total demand minus the hydro contribution.) The revised Elliston, Diesendorf and MacGill proposal includes this recognition and assumes about 23 GW of biomass-gas-electricity capacity in a system intended to meet an average about 23 GW of demand (and including 104 GW of total capacity.) ZCA's Figs. 4.2 and 4.3 show gaps that would be filled by only a small biomass capacity, but again those were benign years; it would be interesting to see how much might have been needed late in 2010.

The efficiency of biomass generation of electricity via burning directly as of the fuel to produce steam is probably under 20% when all factors such as the production and trucking of the biomass are taken into account. Generation via gas produced by pyrolysis is problematic and not yet commercially established, and also probably does not have a good efficiency when all factors are taken into account. AETA's recent review of renewables gave it only a few not very encouraging lines and did not anticipate it general use; "No significant progress has been made on full scale development of such plants and none is anticipated in Australia in the near future." (2012, p. 53.) Weisbach et al. say, biogas-fired plant are "…clearly below the economic limit with no potential of improvements in reach." (2013, p. 24.) Lenzen's review of renewables (2009) and the comments by The Grattan Institute (Wood, et al., 2012) and Syngas Technology, (2013) are similarly not encouraging.

There is also the problem of getting large quantities of biomass to the few solar thermal sites. The magnitude of the transport task has been seen to determine that a biomass energy system must have many smaller plants located close to sources, or the transport cost becomes uneconomic. Thodey (2013) points out that generation efficiency and cost figures deteriorate significantly as plant size decreases.

If we needed enough biomass-electricity capacity to deliver 32 GW, more or less needed in the Elliston, Diesendorf and MacGill proposal, we might have to add another at least $160 billion to the capital cost total when all elements in the sector are taken into account.

**Conclusion.**

The three main concerns in this commentary have been

The ZCA supply target seems to be far too low,

The output conclusions for wind and solar thermal assumed seem to be too optimistic.

The capital cost conclusions seem to be far too low.

The result indicated by combining these factors would be a total system capital cost several times that claimed by ZCA.

Trainer 2011b sets out the derivation of the conclusion that the annual investment cost of the wind, PV and solar thermal plant needed to meet Australia's probable 2050 energy demand would be 13 times the early 2000s ratio of energy investment to GDP in rich countries. There are several additional cost factors that were not included in the exercise and which would multiply this total a number of times, such as the cost of the transmission lines, the very large biomass system, the hydrogen-storage system probably required, the extra capacity needed to cope with peak demand and the occurrence of minimal solar and wind energy availability. These numbers cannot be state at all confident but they indicate the possible magnitude of the capital cost problem when intermittency and redundancy problems are taken into account. The question is not whether technically renewables could provide 100% of energy needed -- it is whether we could afford to do it.

The above discussion is in terms of present capital costs, and ZCA deals in terms of estimated future costs (generally thought to be 33E% lower for solar thermal, but not much lower for wind.) However it is important to recognize that in the first decade or so of the building of renewable capacity it will be present as distinct from future costs would have to be met.

Another important cost consideration is that the cost of all materials and energy inputs to the construction of renewable plant will surely increase significantly in future years.

As I always try to say this is not an argument against transition to renewable energy. It is part of the case that global problems cannot be solved by or within consumer-capitalist society and can only be solved by transition to some kind of Simpler Way.

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